

UNITED STATES
DEPARTMENT OF THE INTERIOR

FINAL

ENVIRONMENTAL STATEMENT

VOLUME 2 OF 3

Proposed
1974 OUTER CONTINENTAL SHELF
OIL AND GAS GENERAL LEASE SALE
OFFSHORE TEXAS

OCS SALE No.34

FES 74-14



Prepared by the
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TABLE OF CONTENTS

VOLUME II

	Page
V. MITIGATING MEASURES IN THE PROPOSED ACTION.	1
A. Oil Spills.	3
1. Regulations	3
2. Inspection.	7
3. Enforcement	11
4. Contingency Action.	17
B. Structures.	24
C. Pipelines	28
D. Other Mitigatory Measures	36
1. Special Stipulations.	36
2. Notices to Lessees and Operators.	42
3. Departures.	43
4. Research on Advanced Technology	44
5. Geophysical Information	44
6. Conservation Practices.	46
7. Other Requirements.	48
VI. UNAVOIDABLE ADVERSE ENVIRONMENTAL EFFECTS	51
A. Effect on Marine Organisms.	51
B. Wetlands and Beaches.	55
C. Deterioration of Air Quality.	55
D. Deterioration of Water Quality.	56
E. Interference with Commercial Fishing Operations	56
F. Interference with Ship Navigation	57
G. Damage to Historical and Archeological Sites, Structures, and Objects	58
H. Interference with Recreational Activities	59
I. Degradation of Aesthetic Values	59
J. Conflict with Other Uses of the Land.	60

	Pag
VII. RELATIONSHIP BETWEEN LOCAL SHORT-TERM USE AND MAINTENANCE AND ENHANCEMENT OF LONG-TERM PRODUCTIVITY	6
VIII. IRREVERSIBLE AND IRRETRIEVABLE COMMITMENT OF RESOURCES.	6
A. Mineral Resources	6
B. Land Resources.	6
C. Fish and Wildlife Resources	6
IX. ALTERNATIVES TO THE PROPOSED ACTION*	6
A. Hold the Sale in Modified Form.	6
1. Details of Tract Selection Process for Proposed Texas Sale.	6
2. Sale Modification Alternatives.	7
B. Withdraw the Sale	7
1. Energy Conservation	8
2. Conventional Oil and Gas Supplies	9
3. Coal.	14
4. Synthetic Sources of Gas and Oil.	18
5. Hydroelectric Power	23
6. Nuclear Power	24
7. Energy Imports.	26
8. Other Energy Sources.	32
9. Combination of Alternatives	39
C. Delay Sale.	40
1. Until New Technology is Available to Provide Increased Environmental Protection.	40
2. Pending Completion of Studies Concerning the Potential Environmental Impacts of Offshore Minerals Development in General and Oil Spills Specifically.	40
3. Pending Development of Land Use and Growth Plans Offshore.	40
4. Pending Completed Implementation of Recommendations Made in Reports on OCS Operating Orders and Regu- lations and a Review of Regulations and Amendments as Necessary.	40
D. Government Exploratory Drilling Before Leasing.	40'

* Tables and Figures Numbered Independently for Rest of the Volume.

V. MITIGATING MEASURES INCLUDED IN THE PROPOSED ACTION

The Department has developed the following strategy for safe development of the mineral resources of the OCS.

Management of the mineral resources of the OCS will be conducted in such a manner as to cause these resources to make a significant contribution toward supporting the present and future national economy at a rate consistent with maximum possible protection of the environment, orderly and timely development of the resource, and receipt of a fair market value return to the Federal Government.

Reasonably safe development of oil and gas resources on the OCS can be achieved through strict enforcement of lease stipulations and obligations, (detailed in the OCS operating regulations and orders) 1/ and must be based on sound operating practices backed by effective contingency actions in the event that pollution occurs as a result of a natural disaster, human error, or equipment failure.

Research and development programs in exploration, production, transportation, containment and clean-up technology, which provide greater safeguards for the environment, are being conducted by the Department of the Interior, other Federal agencies and

1/ OCS operating orders for the Gulf of Mexico have been appended to this statement. See Attachment A.

private industry. The Coast Guard in fiscal year 1972 spent in excess of \$3,000,000 for research and development on oil containment booms, oil recovery devices and techniques for forecasting movement of oil slicks. The oil industry during the period 1966-72 has reportedly committed nearly \$235,000,000 for environmental research and development on air and water pollution. Currently the American Petroleum Institute (API) and the USGS have a cooperative effort underway which will document research work on safety and anti-pollution equipment, recommend additional research, and supervise the management of additional safety or anti-pollution research projects funded by API. As advances are made, OCS operating regulations and orders will be revised and the new technology applied to existing leases as well as new leases. Revisions of the regulations and formulations of lease stipulations may also result from the review of environmental impact statements by the agencies and the interested public.

The following discussion concerns the mitigatory measures which will influence possible adverse impacts that could result from this proposed sale. These measures are presented as they relate to oil spills, offshore structures and pipelines as well as other impact-producing activities associated with OCS oil and gas development.

A. Oil Spills

1. Regulations

Regulations governing OCS oil and gas lease operations in the Gulf of Mexico are contained in Title 30, Code of Federal Regulations and OCS Orders Nos. 1-4, 6, 7, dated August 28, 1969, No. 5, dated June 5, 1972, Nos. 8-9, dated October 20, 1970, No. 11, dated April 5, 1972, and No. 12, dated August 13, 1971. (See Attachment A). Leasing regulations are contained in Title 43, Code of Federal Regulations. The regulations established procedures and requirements to be followed in all stages of lease operations: exploration and development, drilling, production, transportation (pipeline construction and operation) and abandonment.

A general description of operating requirements under the existing regulations follows:

a. Plans: Operating plans must be submitted by the operators and approved by the Geological Survey (GS) before each stage of operations is initiated (exploration, development, abandonment). Approval of all operations must be obtained prior to their commencement.

b. Operator Inspection and Testing: The operator is required to inspect all aspects of the safety systems at specific intervals, e.g., daily pollution inspection on manned facilities, "frequent" inspection on unmanned facilities, monthly test of check valves. Detailed records of inspections and tests are required. 1/

1/ See Vol. 2, Attachment I for drilling and production inspection report forms and the code book which provides interpretation.

c. Reports: The operator is required to report all spills or leakage of oil to GS without delay. He is also required to notify GS of any unusual condition, problem or malfunction within 24 hours. 1/

d. Safety Devices: Required safety devices include subsurface safety devices, high-low pressure shut-in controls, high liquid level shut-in controls, pressure relief valves, automatic fail-close valves at the well head, automatic fire fighting systems, automatic gas detector and alarm systems, and other safety devices on production equipment; high-low pressure sensing devices and automatic shut-in valves on pipelines; and blowout preventers, related well control equipment, and mud system monitoring equipment on drilling wells.

e. Waste Disposal: The lessee is prohibited from disposing into the ocean any oil (except that oil in produced formation water must average no more than 50 ppm) 2/, untreated waste material or other materials which may be harmful to aquatic life or wildlife. Any drilling mud which may contain toxic substance must

1/ 30 CFR 250.45.

2/ OCS Order No. 8 (2.A.(5), Gulf of Mexico, Attachment A.

be neutralized before it can be disposed of in the ocean. Drill cuttings which are predominantly sand and shale, must be processed, and oil removed, before they can be disposed of in the ocean. 1/ Sewage samples shall be collected semi-annually by lessee personnel and the samples submitted to a laboratory for analysis. Results of the analysis will be available on the platforms and rigs for inspection by the USGS technicians. GS personnel are responsible for enforcing the requirement but do not take the samples.

f. Site Clearance: When an installation is no longer needed for development of the lease, the well is plugged with cement and all casings and piling must be severed and removed to at least 15 feet below the ocean floor and the location must be dragged to clear the site of any obstruction.

g. Debris: Regulations and OCS Orders prohibit the disposal of debris into the Gulf of Mexico. Solid waste must be either incinerated or transported to shore for disposal in accordance with applicable requirements under State and Federal law.

h. Contingency Plans and Equipment: The operator is required to have an approved plan for controlling and removing pollution which provides for:

1/ Waste disposals must comply with the 1972 Amendments of the Federal Water Pollution Control Act. Permits for disposals must be obtained from EPA under the National Pollutant Discharge Elimination System. See Sec. V.D.7. of this volume.

- (1) Standby pollution control equipment, including containment booms, skimming apparatus, and approved chemical dispersants immediately available to the operator at a land based location.
- (2) Regular inspection and maintenance of such equipment.

The Oil and Hazardous Substances Pollution Contingency Plan, Gulf Coast Region, is operative and has recently been revised and updated to agree with the National Plan 1/. In addition, the Coast Guard has established the Gulf Coast Team of the National Strike Force (NSF) at the NASA Mississippi Test Facility, Bay St. Louis, Mississippi for the purpose of responding to oil spills in the Gulf of Mexico. The National Strike Force has been established in accordance with the Federal Water Pollution Control Act and the National Oil and Hazardous Substances Contingency Plan.

The Gulf Coast Team is fully operative at this time and presently consists of 14 men with plans to increase to a total of 19 men in the near future. This team is capable of responding to incidents within 2 hours of notification by the appropriate District Commander.

2. Inspection

Evidence of compliance with the regulations and lease requirements is obtained through surveillance of the operations under the lease and enforcement of specific requirements. The inspection system

1/ See also v.A.4.b. of this volume and discussion of the National Oil and Hazardous Substances Pollution Contingency Plan.

of the Geological Survey includes: (1) review and approval of plans before each operating stage is initiated, (2) close review and follow-up as necessary, by GS inspectors, of all reports required of the operator by the regulations and orders, (3) on-site inspection and (4) aerial monitoring through the use of helicopters (operators are also required to inform each other of oil spills or other irregularities which they observe).

a. Operator reports: A comprehensive reporting system covering all oil spills and any unusual conditions (for example: reporting and investigation of a persistent oil slick from an unknown source such as a sunken ship or natural oil seep) is required by the orders and is a key factor in monitoring operations. Operators are also required to maintain records for GS inspection of required periodic tests of safety equipment. Compliance with reporting requirements can be assured only by periodic on-the-site inspection and aerial monitoring.

b. On-site Inspection: During the course of drilling, all operations are inspected at least one time. Leases in certain areas or in a particular development stage may require more inspections to assure the achievement of safety objectives. GS is continuing the systematic inspection program and a more stringent enforcement policy. This has resulted in increased

operator compliance along with greater coverage of production operations and better documentation of inspection results.

A complete drilling inspection is normally conducted on each drilling rig approximately every six weeks. Random inspections may be made more frequently. Depending on the number of drilling rigs in each District, the frequency of inspections on a rig may vary from six to twelve per year. All producing platforms are inspected at least once a year and random inspections are made more frequently on some. The frequency rate for platform inspections is approximately once every nine months.

The total number of warnings issued and suspensions ordered for infractions of OCS Orders which occurred during normal daily inspections from December 1, 1972 through September 30, 1973, are as follows:

<u>WARNINGS</u>			<u>SUSPENSIONS</u>		
<u>Drilling</u>	<u>Workover</u>	<u>Production</u>	<u>Drilling</u>	<u>Workover</u>	<u>Production</u>
34	2	1,529	14	3	764

Approximately 113 on-site inspections of pollution incidents were made from December 1, 1972 through September 30, 1973, in response to reports submitted by operators.

re the results of on-site inspections performed in response
tions made during pollution surveillance flights conducted
1, 1972 through September 30, 1973:

<u>actions</u>	<u>No. Platforms</u>	<u>No. Wells</u>	<u>Warnings</u>	<u>Suspensions</u>
	131	797	14	20

ntensive inspections is used on OCS leases. Periodically,
inspectors devote a week to a special inspection, whereupon
tforms and drilling wells are inspected on a random basis;
ring other periods are conducted on a regular basis with
erations believed to require special attention. The GS
e in the Gulf of Mexico has increased from 7 technicians
s as of July 1, 1969 to 28 technicians and 16 engineers
r 30, 1973. During the period November 1, 1972 through
1973, technicians spent 3,099 inspection days or 25,467 man-
;ineers 314 inspection days or 2,485 man-hours in the field.
actions were conducted on 933 major producing platforms and
tforms (out of a total of 2000) in the Gulf of Mexico from
972 through September 30, 1973. Also, during this time
nspections of single-wells or satellites were made by boat.
60% of these inspections were unannounced. Included in
ions were 10,300 well completions. Also, during this time
nspections of drilling rigs were conducted. As of
1973 in a total of 11,383 holes, there were 9,622 comple-
: of producing oil and gas on the OCS lands offshore

Louisiana and Texas. 1/ Approximately 65 drilling rigs were operating in Gulf of Mexico OCS waters at the end of September, 1973.

c. Aerial Monitoring: "Fly-overs" of the OCS operating areas are programmed on a seven day per week basis by GS inspectors. Any indications of oil pollution or other non-compliance will be followed immediately by an on-site inspection.

During the period January 1 through September 30, 1973, 1,106 pollution surveillance flights were made. The helicopters chartered by the Geological Survey for use of the inspecting personnel flew a total of 4,088 hours.

3. Enforcement

The enforcement policy is intended to: (1) reduce the frequency of non-compliance with lease requirements which may lead to loss of life, loss of property, or damage to the environment; and (2) maintain uniform enforcement standards to be applied to all operations affecting OCS lands in the Gulf of Mexico. When, in the course of an inspection, a requirement pertaining to the prevention of oil pollution or any other safety hazard is found to be in non-compliance, the operation will be shut-in until it is brought into compliance. After a

1/ This figure does not include service completions.

shut-in, the operation can only be resumed by authorization of the GS; in all cases, this requires reinspection or a waiver of the inspection requirement. Minor incidents of non-compliance may require only a warning that corrections be made within a week. The operations will be shut-in if the required corrections are not made.

Additional penalties for non-compliance are specific in P.L. 83-212, Outer Continental Shelf Lands Act, Sec. 5(a)(2). "Any person who knowingly and willfully violates any rule or regulation prescribed by the Secretary for the prevention of waste, the conservation of the natural resources, or the protection of correlative rights shall be deemed guilty of a misdemeanor and punishable by a fine of not more than \$2,000 or by imprisonment, and each day of violation shall be deemed to be a separate offense." Also Sec. 5(b)(1) and (2) provide for cancellation of non-producing and producing leases by notice subject to judicial review or appropriate judicial proceedings.

The following tables (Tables 1, 2, 3) indicate equipment malfunctions detected during inspections and enforcement actions over three separate periods. Minor incidents of non-compliance result in formal warnings while incidents of non-compliance of a potentially more hazardous nature result in well or platform shut-ins until the operation is in full compliance with regulations and orders.

These tables indicate specific items found to be in non-compliance during special inspections. Basic pollution control items of production equipment in which malfunctions were detected for the time periods identified are as follows:

Table 1 EQUIPMENT MALFUNCTION DETECTED DURING JANUARY
THROUGH NOVEMBER, 1971 SPECIAL INSPECTIONS

	<u>No. Checked</u>	<u>Operable</u>	<u>Inoperable or not within acceptable tolerances</u>	<u>Percent Failure</u>
Surface Safety valves	2392	2306	86	3.6%
Flowline sensors	4166	4081	85	2.0%
Check Valves	2222	2052	170	7.7%
Pressure vessels				
High pressure sensors	908	875	33	3.6%
Low pressure sensors	765	744	21	2.8%
Low level shut-in	511	481	30	5.9%
High level shut-in	460	439	21	4.6%
Total	11,424	10,978	446	3.9%

Table 2 EQUIPMENT MALFUNCTION DETECTED DURING JANUARY
THROUGH NOVEMBER 1972 SPECIAL INSPECTION

	<u>No. Checked</u>	<u>Operable</u>	<u>Inoperable or not within acceptable tolerances</u>	<u>Percent Failure</u>
Surface Safety valves	1533	1480	53	3.5%
Flowline sensors	3021	2982	39	1.3%
Check Valves	1434	1370	64	4.5%
Pressure Vessels				
High pressure sensors	961	942	19	2.0%
Low pressure sensors	610	600	10	1.6%
High level shut-in	351	345	6	1.7%
Low level shut-in	323	314	9	2.8%
Total	8,233	8,033	200	2.4%

Table 3 EQUIPMENT MALFUNCTIONS DETECTED JANUARY THROUGH
SEPTEMBER, 1973 SPECIAL INSPECTIONS

	<u>No. Checked</u>	<u>Operable</u>	<u>Inoperable or not within acceptable tolerances</u>	<u>Percent Failure</u>
Surface safety valves	1,188	1,131	57	4.8%
Flowline sensors	385	378	7	1.8%
Check valves	1,170	1,092	78	6.7%
Pressure Vessels				
High pressure sensors	857	841	16	1.8%
Low pressure sensors	521	514	7	1.3%
High level shut-in	217	212	5	2.2%
Low level shut-in	<u>258</u>	<u>251</u>	<u>7</u>	<u>2.7%</u>
Total	4,596	4,419	177	3.9%

Subsurface operated subsurface safety valves are periodically pulled from the wells and checked. This requires removing the valve from the well to inspect and repair or adjust as necessary and reinstall. One company utilized test stands to test the valves performance characteristics under simulated flow and pressure conditions. Surface operated subsurface safety valves are tested in place by releasing hydraulic pressure within the closed system to close the valve and repressuring to open. An average reporting period from May 1973 through July 1973 resulted in approximately 3,000 subsurface safety valves being checked. Of this amount there were 394 failed components detected in the valves but a number of the valves had more than one failed component.

Companies fined in District Court for failure to install subsurface safety devices in offshore oil wells during 1970 in the Gulf of Mexico are presented below (Table 4). Each company entered a plea of nolo contendere. The maximum fine for violation of the Outer Continental Shelf Lands Act is \$2,000 per count.

Table 4. MAXIMUM FINES

Chevron Oil Company	\$1,000,000
Gulf Oil Company	250,000
Tenneco	32,000
Kerr-McGee	20,000
Mobil	150,000
Continental	242,000
Humble	300,000
Shell	340,000
Union of California	<u>24,000</u>
	\$2,358,000

No data for direct comparison of pollution incidences for similar time periods before and after the current "more stringent enforcement policy" are available. However, experienced personnel, private and government, are aware that after public attention was focused on the oil spill at Santa Barbara in January 1969, there has been a great deal less oil pollution in the Gulf from normal oil and gas producing operations. The public awareness, concern, and demand to prevent pollution have been a major factor in the reduction of oil spills.

In the past, major events were catalogued, but less serious events where often not reported. Occasionally, some years ago, wells were even intentionally flowed into the water for short periods during clean-up operations. Now, sophisticated burning devices are designed to consume this well clean-up oil without air or water pollution. More automatic equipment is now in use to shut-in production whenever a leak occurs in pipeline or production facilities. These include but are not limited to pressure sensors and high and low level controls. Drip pans are placed under valves, vessels, and the production system to prevent leaking oil from escaping into the waters of the Gulf.

New reporting and investigative procedures established in the last two years have increased many fold the number of pollution incidents reported as well as the time spent by GS personnel in surveillance flights by helicopters in assuring proper documentation of pollution events.

There have been several detailed studies recently completed concerning operating practices on the OCS. The Department's response to these studies and the steps being taken at this time will improve many facets of OCS management practices. For a discussion of these studies see Vol. 1, Sec. 1.G.

4. Contingency Action

Oil spills will occasionally occur as a result of natural disasters, equipment failure or human error. In the event that such an emergency occurs, the following action will be taken:

a. Requirements of OCS Order No. 7 1/

In the case of any spill, the operator is required to initiate action to control and remove the oil pollution in accordance with his approved emergency plan. In any case, a spill or leakage of less than 15 bbls. requires a report from the operator as to the nature of the spill or leakage, why it occurred and what steps were taken to correct it. A spill of 15-20 bbls. must be reported by telephone immediately to GS and confirmed in writing. A spill of over 50 bbls, or one of any magnitude that cannot be immediately controlled, must be reported immediately to the Coast Guard and the Environmental Protection Agency as well as to GS.

b. Regional or National Contingency Plans

If the operator should be unable to control and remove the pollution, the Regional or National Oil and Hazardous

1/ See Attachment A.

Substances Pollution Contingency Plan may be activated and the designated Federal On Scene Coordinator would direct control and clean-up operations at the operator's expense. This has never been necessary in the case of any spill from OCS operations to date.

The Regional or National Oil and Hazardous Substances Pollution Contingency Plan was developed pursuant to the provisions of the Federal Water Pollution Control Act as amended (33 U.S.C. 1101). (EPA has published the revised National Oil and Hazardous Substance Pollution Contingency Plan as required by the Federal Water Pollution Control Act Amendments of 1972.) Section 11(c)(2) of that statute authorizes the President, within sixty days after the sections becomes effective, to prepare and publish such a Plan. The Plan provides for efficient, coordinated, and effective action to minimize damage from oil (and other) discharges, including containment, dispersal, and removal. The Plan includes (a) assignment of duties and responsibilities, (b) identification, procurement, maintenance and storage of equipment and supplies, (c) establishment of a strike force and emergency task forces, (d) a system of surveillance and notice, (e) establishment of a national center to coordinate response operations, (f) procedures and techniques to be employed in identifying, containing, dispersing and removing oil, and (g) a schedule identifying dispersants and other chemicals that may be used in carrying out the Plan, the waters in which they may be

used, and quantities which may be safely used. 1/ The Plan is revised from time to time as necessary. Operation of the National Contingency Plan requires a nationwide net of regional contingency plans. Guidelines for that nationwide net are established in the National Plan. This plan provides for a pattern of coordinated and integrated responses to pollution spills of departments and agencies of the Federal Government. It establishes a national response team and provides guidelines for the establishment of regional contingency plans and response teams. The Plan also promotes the coordination and direction of Federal, State, and local response systems and encourages the development of local government and private capabilities to handle such pollution spills.

The objectives of the Plan are: to develop appropriate preventive and preparedness measures and effective systems for discovering and reporting the existence of a pollution spill; to institute promptly, measures to restrict further spread of the pollutant; to assure that the public health, welfare, and natural resources are provided adequate protection; to provide for the application of techniques to clean up-and dispose of the collected pollutants; to provide for a scientific response to spills as appropriate;

1/ Annex X of the Plan basically sets forth a no dispersant policy. Exceptions can be made for safety reasons (to prevent fire or explosions) or for certain other circumstances such as the protection of endangered waterfowl. However, the approval of EPA is required, except in case of safety when the approval of the On-Scene Coordinator is required.

to provide strike forces of trained personnel and adequate equipment to polluting spills; to institute actions to recover clean-up cost; and, to effect enforcement of existing Federal statutes and regulations issued thereunder. Detailed guidance toward the accomplishment of these objectives is contained in the basic Plan, the annexed, and the regional plans.

The Plan is effective for all United States navigable waters including inland rivers, Great Lakes, coastal territorial waters, and the contiguous zone and high seas beyond this zone where a threat exists to United States waters, shoreface, or shelf-bottom. Its provisions are applicable to all Federal agencies.

A memorandum of understanding between the Departments of the Interior and Transportation outlines the respective responsibilities of the Geological Survey and the Coast Guard under the National Contingency Plan. GS is responsible for the coordination and direction of measures to abate the source of pollution when the source is an oil, gas, or sulphur well. This responsibility includes the authority to determine whether pollution control operations within a 500 meter radius of the pollution source should be suspended to facilitate measures to abate the source of pollution. The Coast Guard is responsible for coordination and direction of measures to contain and remove pollutants, and shall furnish or provide for the

On Scene Coordinator with authority and responsibilities as provided by the National Contingency Plan.

The State of Texas has its own Oil and Hazardous Substances Pollution Contingency Plan. This plan, effective for all waters within the territorial limits of the State, provides procedures for a coordinated response to spills of oil or other pollutants by State agencies concerned with environmental protection, and public health and welfare. It also outlines methods by which spills and accidental discharges will be reported to the appropriate State regulatory agencies. The Texas Water Quality Board is the lead agency in coordinating this plan.

c. Petroleum Industry Contingency Actions

(i) Inventory of Known Resources Available for
Emergency Oil Spill Control and Clean-Up

From the upper Texas Coast to the Mississippi Delta region offshore operators maintain a large inventory of various kinds of equipment that could be put to use on short notice for containing and cleaning up an oil spill and killing the source of the spill. This inventory includes 177 boats ranging from 30 foot crewboats to 165 foot utility and cargo vessels, 64 helicopters, 103 fixed-wing aircraft. For a complete inventory of oil spill containment and clean-up equipment see Vol. 2 Attachment J

(ii) Clean Gulf Associates

Clean Gulf Associates is a non-profit organization formed by thirty-three companies 1/ operating in the OCS. Their purpose is to provide for a stock pile of oil spill containment and clean-up materials for use by member companies in offshore and estuarine areas. Clean Gulf Associates has contracted, effective August 1, 1972, with Halliburton Services to supply equipment, materials and personnel necessary to contain

1/ These thirty-three member companies produce 98% of offshore petroleum.

and clean-up spills in the Gulf of Mexico to the limits of the OCS lying offshore and seaward of the States of Texas, Louisiana, Mississippi, Alabama, and Florida.

All of the tracts considered in this proposed lease sale fall within this area. Before any drilling commences, should this proposed sale be held, an inventory of pollution combatting equipment would be stockpiled at a strategic location. Should oil reservoirs be found and production ensue, a permanent base for containment and clean-up equipment will be established. For a special stipulation concerning oil spill containment and clean-up equipment available in the proposed sale area see Section V.D.1.

At the present time, Halliburton maintains four types of recovery/clean-up systems for development at two primary bases located at Intercoastal City, and Grand Isle, Louisiana, and a sub-base at Venice, Louisiana and include:

- (1) Fast response open sea/bay skimmer system
- (2) High volume open sea skimmer system
- (3) Shallow water skimmer system
- (4) Auxiliary shallow water and beach clean-up equipment.

For a complete inventory of oil spill containment and clean-up equipment see Vol. 2 Attachment J.

B. Structures

If a ship strays from established safety fairways, oil and gas platforms can pose a hazard to commercial shipping. This hazard, however, is minimized by the fact that safety fairways are clearly designed on navigation charts. Directional drilling from outside safety lanes is used to develop tracts lying partially in safety lanes. Pertinent portions of the Federal Regulations (33 CFR Sec. 209.135(b), 1971), governing shipping fairways and anchorage areas are as follows:

"The Department of the Army will grant no permits for the erection of structures in the area designated as fairways, since structures located therein would constitute obstructions to navigation. The Department of the Army will grant permits for the erection of structures within an area designated as an anchorage area, but the number of structures will be limited by spacing as follows: The center of a structure to be erected shall be not less than two (2) nautical miles from the center of any existing structures. In a drilling or production complex, associated structures shall be as close together as practicable having the consideration for the safety factors involved. A complex of associated structures, when connected by walkways, shall be considered one structure for the purposes of spacing. A vessel fixed in place by moorings and used in conjunction with the associated structures of a drilling or production complex, shall be considered an attendant vessel and its extent shall include its moorings. When a drilling or production complex includes an attendant vessel and the complex extends more than five hundred (500) yards from the center of the complex, a structure to be erected shall be not closer than two (2) nautical miles from the near outer limit of the complex. An underwater completion installation in an anchorage area shall be considered a structure and shall be marked with a lighted buoy as approved by the United States Coast Guard."

Development of the tracts in this proposed sale which lie partially within shipping fairways or anchorage areas if leased will be subject to Federal regulations as presented above so far as placement of structures is concerned and this would help mitigate any potential impact due to the proximity of structures to relatively high frequency sea traffic.

Commercial vessels are required to report to the Coast Guard whenever a casualty results in any of the following: (a) actual physical damage to property in excess of \$1500, (b) material damage affecting the seaworthiness or efficiency of a vessel, (c) stranding or grounding, (d) loss of life, (e) injury causing any person to remain incapacitated for a period in excess of 72 hours; except injury to harbor workers not resulting in death and not resulting from vessel casualty or vessel equipment casualty. Drilling and production platforms (artificial islands) are required to report to the Coast Guard when involved in a casualty or accident and if any of the following occur: (a) if hit by a vessel and damage to property exceeds \$1500, (b) damage to fixed structure exceeds \$25,000, (c) material damage affecting usefulness of lifesaving or firefighting equipment, or (d) loss of life.

Under some conditions, offshore structures are an obstacle to commercial fishing activities. Depending on currents and underwater obstacles an offshore structure can remove areas of trawling and purse seining waters. Heavy concentrations of platforms can make trawling and purse seining difficult.

In the past, major events were catalogued, but less serious events where often not reported. Occasionally, some years ago, wells were even intentionally flowed into the water for short periods during clean-up operations. Now, sophisticated burning devices are designed to consume this well clean-up oil without air or water pollution. More automatic equipment is now in use to shut-in production whenever a leak occurs in pipeline or production facilities. These include but are not limited to pressure sensors and high and low level controls. Drip pans are placed under valves, vessels, and the production system to prevent leaking oil from escaping into the waters of the Gulf.

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Oil spills will occasionally occur as a result of natural disasters, equipment failure or human error. In the event that such an emergency occurs, the following action will be taken:

a. Requirements of OCS Order No. 7 1/

In the case of any spill, the operator is required to initiate action to control and remove the oil pollution in accordance with his approved emergency plan. In any case, a spill or leakage of less than 15 bbls. requires a report from the operator as to the nature of the spill or leakage, why it occurred and what steps were taken to correct it. A spill of 15-20 bbls. must be reported by telephone immediately to GS and confirmed in writing. A spill of over 50 bbls, or one of any magnitude that cannot be immediately controlled, must be reported immediately to the Coast Guard and the Environmental Protection Agency as well as to GS.

b. Regional or National Contingency Plans

If the operator should be unable to control and remove the pollution, the Regional or National Oil and Hazardous

1/ See Attachment A.

Substances Pollution Contingency Plan may be activated and the designated Federal On Scene Coordinator would direct control and clean-up operations at the operator's expense. This has never been necessary in the case of any spill from OCS operations to date.

The Regional or National Oil and Hazardous Substances Pollution Contingency Plan was developed pursuant to the provisions of the Federal Water Pollution Control Act as amended (33 U.S.C. 1101). (EPA has published the revised National Oil and Hazardous Substance Pollution Contingency Plan as required by the Federal Water Pollution Control Act Amendments of 1972.) Section 11(c)(2) of that statute authorizes the President, within sixty days after the sections becomes effective, to prepare and publish such a Plan. The Plan provides for efficient, coordinated, and effective action to minimize damage from oil (and other) discharges, including containment, dispersal, and removal. The Plan includes (a) assignment of duties and responsibilities, (b) identification, procurement, maintenance and storage of equipment and supplies, (c) establishment of a strike force and emergency task forces, (d) a system of surveillance and notice, (e) establishment of a national center to coordinate response operations, (f) procedures and techniques to be employed in identifying, containing, dispersing and removing oil, and (g) a schedule identifying dispersants and other chemicals that may be used in carrying out the Plan, the waters in which they may be

used, and quantities which may be safely used. 1/ The Plan is revised from time to time as necessary. Operation of the National Contingency Plan requires a nationwide net of regional contingency plans. Guidelines for that nationwide net are established in the National Plan. This plan provides for a pattern of coordinated and integrated responses to pollution spills of departments and agencies of the Federal Government. It establishes a national response team and provides guidelines for the establishment of regional contingency plans and response teams. The Plan also promotes the coordination and direction of Federal, State, and local response systems and encourages the development of local government and private capabilities to handle such pollution spills.

The objectives of the Plan are: to develop appropriate preventive and preparedness measures and effective systems for discovering and reporting the existence of a pollution spill; to institute promptly, measures to restrict further spread of the pollutant; to assure that the public health, welfare, and natural resources are provided adequate protection; to provide for the application of techniques to clean up-and dispose of the collected pollutants; to provide for a scientific response to spills as appropriate;

1/ Annex X of the Plan basically sets forth a no dispersant policy. Exceptions can be made for safety reasons (to prevent fire or explosions) or for certain other circumstances such as the protection of endangered waterfowl. However, the approval of EPA is required, except in case of safety when the approval of the On-Scene Coordinator is required.

to provide strike forces of trained personnel and adequate equipment to polluting spills; to institute actions to recover clean-up cost; and, to effect enforcement of existing Federal statutes and regulations issued thereunder. Detailed guidance toward the accomplishment of these objectives is contained in the basic Plan, the annexed, and the regional plans.

The Plan is effective for all United States navigable waters including inland rivers, Great Lakes, coastal territorial waters, and the contiguous zone and high seas beyond this zone where a threat exists to United States waters, shoreface, or shelf-bottom. Its provisions are applicable to all Federal agencies.

A memorandum of understanding between the Departments of the Interior and Transportation outlines the respective responsibilities of the Geological Survey and the Coast Guard under the National Contingency Plan. GS is responsible for the coordination and direction of measures to abate the source of pollution when the source is an oil, gas, or sulphur well. This responsibility includes the authority to determine whether pollution control operations within a 500 meter radius of the pollution source should be suspended to facilitate measures to abate the source of pollution. The Coast Guard is responsible for coordination and direction of measures to contain and remove pollutants, and shall furnish or provide for the

On Scene Coordinator with authority and responsibilities as provided by the National Contingency Plan.

The State of Texas has its own Oil and Hazardous Substances Pollution Contingency Plan. This plan, effective for all waters within the territorial limits of the State, provides procedures for a coordinated response to spills of oil or other pollutants by State agencies concerned with environmental protection, and public health and welfare. It also outlines methods by which spills and accidental discharges will be reported to the appropriate State regulatory agencies. The Texas Water Quality Board is the lead agency in coordinating this plan.

c. Petroleum Industry Contingency Actions

(i) Inventory of Known Resources Available for
Emergency Oil Spill Control and Clean-Up

From the upper Texas Coast to the Mississippi Delta region offshore operators maintain a large inventory of various kinds of equipment that could be put to use on short notice for containing and cleaning up an oil spill and killing the source of the spill. This inventory includes 177 boats ranging from 30 foot crewboats to 165 foot utility and cargo vessels, 64 helicopters, 103 fixed-wing aircraft. For a complete inventory of oil spill containment and clean-up equipment see Vol. 2 Attachment J

(ii) Clean Gulf Associates

Clean Gulf Associates is a non-profit organization formed by thirty-three companies 1/ operating in the OCS. Their purpose is to provide for a stock pile of oil spill containment and clean-up materials for use by member companies in offshore and estuarine areas. Clean Gulf Associates has contracted, effective August 1, 1972, with Halliburton Services to supply equipment, materials and personnel necessary to contain

1/ These thirty-three member companies produce 98% of offshore petroleum.

and clean-up spills in the Gulf of Mexico to the limits of the OCS lying offshore and seaward of the States of Texas, Louisiana, Mississippi, Alabama, and Florida.

All of the tracts considered in this proposed lease sale fall within this area. Before any drilling commences, should this proposed sale be held, an inventory of pollution combatting equipment would be stockpiled at a strategic location. Should oil reservoirs be found and production ensue, a permanent base for containment and clean-up equipment will be established. For a special stipulation concerning oil spill containment and clean-up equipment available in the proposed sale area see Section V.D.1.

At the present time, Halliburton maintains four types of recovery/clean-up systems for development at two primary bases located at Intercoastal City, and Grand Isle, Louisiana, and a sub-base at Venice, Louisiana and include:

- (1) Fast response open sea/bay skimmer system
- (2) High volume open sea skimmer system
- (3) Shallow water skimmer system
- (4) Auxiliary shallow water and beach clean-up equipment.

For a complete inventory of oil spill containment and clean-up equipment see Vol. 2 Attachment J.

B. Structures

If a ship strays from established safety fairways, oil and gas platforms can pose a hazard to commercial shipping. This hazard, however, is minimized by the fact that safety fairways are clearly designed on navigation charts. Directional drilling from outside safety lanes is used to develop tracts lying partially in safety lanes. Pertinent portions of the Federal Regulations (33 CFR Sec. 209.135(b), 1971), governing shipping fairways and anchorage areas are as follows:

"The Department of the Army will grant no permits for the erection of structures in the area designated as fairways, since structures located therein would constitute obstructions to navigation. The Department of the Army will grant permits for the erection of structures within an area designated as an anchorage area, but the number of structures will be limited by spacing as follows: The center of a structure to be erected shall be not less than two (2) nautical miles from the center of any existing structures. In a drilling or production complex, associated structures shall be as close together as practicable having the consideration for the safety factors involved. A complex of associated structures, when connected by walkways, shall be considered one structure for the purposes of spacing. A vessel fixed in place by moorings and used in conjunction with the associated structures of a drilling or production complex, shall be considered an attendant vessel and its extent shall include its moorings. When a drilling or production complex includes an attendant vessel and the complex extends more than five hundred (500) yards from the center of the complex, a structure to be erected shall be not closer than two (2) nautical miles from the near outer limit of the complex. An underwater completion installation in an anchorage area shall be considered a structure and shall be marked with a lighted buoy as approved by the United States Coast Guard."

Development of the tracts in this proposed sale which lie partially within shipping fairways or anchorage areas if leased will be subject to Federal regulations as presented above so far as placement of structures is concerned and this would help mitigate any potential impact due to the proximity of structures to relatively high frequency sea traffic.

Commercial vessels are required to report to the Coast Guard whenever a casualty results in any of the following: (a) actual physical damage to property in excess of \$1500, (b) material damage affecting the seaworthiness or efficiency of a vessel, (c) stranding or grounding, (d) loss of life, (e) injury causing any person to remain incapacitated for a period in excess of 72 hours; except injury to harbor workers not resulting in death and not resulting from vessel casualty or vessel equipment casualty. Drilling and production platforms (artificial islands) are required to report to the Coast Guard when involved in a casualty or accident and if any of the following occur: (a) if hit by a vessel and damage to property exceeds \$1500, (b) damage to fixed structure exceeds \$25,000, (c) material damage affecting usefulness of lifesaving or fire-fighting equipment, or (d) loss of life.

Under some conditions, offshore structures are an obstacle to commercial fishing activities. Depending on currents and underwater obstacles an offshore structure can remove areas of trawling and purse seining waters. Heavy concentrations of platforms can make trawling and purse seining difficult.

The erection of more structures on the OCS may affect commercial fishing operations. The impact from platforms may be kept to a minimum, however, by only allowing those structures necessary for proper development and production of the mineral resources, and by placing them with due regard to fishing operations and other competing uses which are evident at the time of platform approval.

The Area Oil and Gas Supervisor considers the views of commercial fishing organizations such as the Gulf State Marine Fisheries Committee with regard to placement of platforms. The Supervisor also from time to time requests information from the Department of Commerce, National Oceanic and Atmospheric Administration, and National Marine Fisheries Service to be used in his decision-making process of approving or disapproving platform installation. Within the constraints of location of the reservoirs and the technology necessary to drill directional wells, the Supervisor is mindful that platform location is an important consideration for commercial fisheries and does make decisions to minimize the impact of platform location on the commercial fishing industry.

In an effort to further mitigate the impact of offshore structures resulting from this proposed sale with regard to commercial fishing and other significant existing or future uses of the leased area, a lease stipulation giving effect to the following will be applied to all blocks in this proposed offering in the event they should lease:

24

"Structures for drilling or production, including pipelines, shall be kept to the minimum necessary for proper exploration, development and production and to the greatest extent consistent therewith, shall be placed so as not to interfere with other significant uses of the Outer Continental Shelf including commercial fishing. To this end, no structure for drilling or production, including pipelines, may be placed on the Outer Continental Shelf until the Supervisor has found that the structure is necessary for the proper exploration, development, and production of the leased area and that no reasonable alternative placement would cause less interference with other significant uses of the Outer Continental Shelf including commercial fishing. The lessee's exploratory and development plans, filed under 30 CFR 250.34, shall identify the anticipated placement and grouping of necessary structures, including pipelines, showing how such placement and grouping will have the minimum practicable effect on other significant uses of the Outer Continental Shelf, including commercial fishing.

C. Pipelines

The potential impact of each specific nearshore and coastal pipeline construction project are considered by the Department in its review of Corps of Engineers permit applications.

The offshore petroleum industry suggests a possible need for one new pipeline in order to develop the tracts proposed in this sale, and has tentatively identified areas of interest for bringing it ashore. The Department of the Interior will receive applications on pipelines to be installed on the OCS and after considering all factors may approve pipeline rights-of-way pursuant to 43 CFR 2883. Authority to grant rights of use or easement for pipelines will be made pursuant to 30 CFR 250.18 and 250.19.

Agencies having responsibility or jurisdiction over all or part of oil and gas pipeline installation or operation in Federal coastal areas are:

(1) Department of the Interior, (a) Bureau of Land Management--rights-of-way for common carrier pipelines on the OCS, (b) Geological Survey--jurisdiction over producer owned gathering lines and flow-lines on the OCS, (c) Bureau of Sport Fisheries and Wildlife--protection of fish and wildlife resources and their habitat through consultation with the Corps of Engineers in the process of issuing Federal permits in navigable waters; (2) U.S. Army Corps of Engineers--issues permits for construction (including pipelines) on OCS and in other navigable waters; (3) Federal Power Commission--grants certificates of convenience and necessity prior to construction of interstate natural gas pipelines; (4) Interstate

Commerce Commission--grants approval of the tariff rates for transportation of oil by common-carrier pipelines; (5) Department of Transportation, Office of Pipeline Safety--establishes standards for pipeline construction, operation and maintenance; and (6) Department of Commerce, National Oceanic and Atmospheric Administration, National Marine Fisheries Service--protection of marine fishery resources and their habitat (in coordination with the Bureau of Sport Fisheries and Wildlife), through consultation with the Corps of Engineers in the process of issuing Federal permits in navigable waters.

At present the cooperative effort between the Department of the Interior and the Corps of Engineers, and the National Marine Fisheries Service and State conservation agencies is responsible for minimizing the impact of pipeline (and other) construction in navigable waters of the United States. The Corps of Engineers, through authority of the Rivers and Harbors Act of 1899, (33 U.S.C. 403) asserts authority over, and requires a permit for construction in all navigable waters subject to the Submerged Lands Act (43 U.S.C. §1301) and includes all lands permanently or periodically covered by tidal waters up to the line of mean high tide.

The Environmental Protection Agency reviews and comments on dredging projects in navigable waters in accordance with a memorandum of understanding with the Corps of Engineers dated July 13, 1967.

The National Oceanic and Atmospheric Administration (through its National Marine Fisheries Service) has been vested with responsibility for participation in matters relating to marine and estuarine areas.

The Department of the Interior and its Bureau of Sport Fisheries and Wildlife has responsibility and authority under several statutes, including the Fish and Wildlife Act of 1956, the Estuary Protection Act, the Endangered Species Conservation Act, the Migratory Bird Conservation Act, the Fish and Wildlife Conservation Act, the Marine Mammals Protection Act, and various international treaties enacted to preserve, conserve, protect and enhance fish and wildlife resources and their habitat.

The Bureau of Sport Fisheries and Wildlife, with assistance from appropriate State and Federal agencies, including the National Marine Fisheries Service now reviews all applications to the Corps of Engineers for permits to construct pipelines in navigable waters and assess their potential impact on fish and wildlife resources and the environment. When appropriate, the Bureau recommends to the Corps specific modification of project plans which are needed to reduce impact on these resources. Occasionally a project plan is so conceived that significant impact cannot be avoided, but at the same time, a satisfactory alternative may be available; in such cases, a recommendation that the permit not be issued would be appropriate. At least one court decision has indicated that the Corps of Engineers has the authority

under the Rivers and Harbors Act to condition or deny a permit on the basis of environmental considerations. 1/

It can be seen from this presentation that Federal responsibility or authority for pipeline installation or operation on submerged coastal lands is fragmented, with responsibility vested not in one or two agencies, but many, and its jurisdictional authority for pipeline placement limited in a shoreward direction to the line of mean high tide or to where pipelines cross navigable channels. The area of onshore impact from pipeline installation falls within the purview of state or local authorities and private landowners.

The question the remaining portion of this section on pipeline will attempt to answer is, given the above mentioned authorities and responsibilities, what measures can be taken to mitigate impacts from pipeline installations expected to result from this proposed sale?

The Department will conduct an environmental analysis on any application for a pipeline right-of-way that it receives. If it is determined that the construction of a pipeline will have a major impact on the marine or coastal environment, then an environmental statement will be prepared.

1/ See Zabel v. Tabb, 430 F. 2n 199 (5th Cir. 1970).

Federal, State or local authorities or private landowners may take measures to require, depending upon circumstances and location, that pipelines be buried; that canals in wetland areas be backfilled where possible, that bulkheads be erected and maintained in marsh areas to prevent saltwater intrusion; that specific types of dredging equipment be used and specific methods for placement or disposal of spoil be required; that beach and dune areas crossed by pipelines be restored; that pipeline installations in sensitive or valuable areas be seasonally timed so as to occur, for example, during low periods of tourist and recreational activities, or prohibited during acute periods of nesting of waterfowl or migrations of fish and wildlife; or, that pipeline corridors be established.

Some potential adverse effects related to pipeline placements resulting from OCS sales occur onshore and are generally outside our authority to apply mitigatory measures. However, we are in a position to apply mitigatory measures to adverse impacts resulting from pipeline placement in Federal offshore areas. In this context, the Department will establish, wherever feasible, pipeline corridors in the area of this proposed sale. To better accomplish this goal a special stipulation will be applied to all leases that issue in the event this proposed sale should proceed the effect of which will be as follows:

The lessor specifically reserves the right to require any pipelines between a structure on the Outer Continental Shelf and an onshore facility to be placed in certain designated areas or corridors through the submerged lands of the Outer Continental Shelf.

We believe that if pipelines which result from this proposed sale are required to be placed in established corridors, wherever feasible, this will allow for accomplishment of the following mitigatory measures:

1. Mitigation of a situation consisting of a scattering of pipelines over a vast area of submerged lands (i.e., the bowl of noodles effect) which presently exists offshore Louisiana.
 2. Reduction in the number of incidents involving interference of pipelines with commercial trawl and purse fishing activities by confining or limiting the area of the offshore that can be utilized for pipeline placement.
 3. Limitation on the area subjected to bottom disruption and sediment suspension during pipeline placement.
 4. Reduction in the number of onshore points needed to bring pipelines ashore, thereby reducing area of beach and estuarine habitat to be disrupted by pipeline excavation.
 5. Identification of corridors can be easily plotted on maps thereby providing added protection against ships dropping anchors on pipelines and providing overall for ease in monitoring the lines for leaks and spills.
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5. Identification of corridors can be easily plotted on maps thereby providing added protection against ships dropping anchors on pipelines and providing overall for ease in monitoring the lines for leaks and spills.

6. Systemization of pipeline planning and Federal-State cooperation and coordination will be enhanced and can lead to environmental management of pipelines so as to reduce or eliminate adverse effects on highly valuable, critically vulnerable resources and activities of the coastal zone.

To help accomplish this goal, an inhouse study will be undertaken by Bureau of Land Management's Environmental Assessment Team in New Orleans, if this sale is held, for the purpose of identifying the potentially least environmentally hazardous areas offshore Texas for pipeline corridor locations. Criteria involving pipeline corridor planning will be established giving high priority to protection of bottom and shoreline resources. Once corridor routes are tentatively identified, coordination with appropriate State authorities will be undertaken. A coordinated Federal-State effort is encouraged if corridor routings are to be implemented effectively and in such a way as to minimize or eliminate, wherever possible, potential environmental damage resulting from pipeline installation and operations.

The Department will conduct an environmental analysis based on the facts and information generated from the process outlined above. If it is determined that official establishment of pipeline corridors will constitute a major Federal action requiring preparation of an

environmental impact statement then such a statement will be prepared in accordance with Section 102(G) of the National Environmental Policy Act. In any event, corridor routes must be established before any production from this proposed sale ensues. We estimate production could occur within approximately three to five years from the date of the sale.

In addition to the above efforts to mitigate potential impacts associated with pipelines, the Bureau of Land Management and the Geological Survey, by virtue of a memorandum of understanding, have taken steps to clearly define their respective administrative and operational roles for improved OCS pipeline management. The purposes and objectives are to: 1) minimize or eliminate environmental damage; 2) better serve industry and public interests; and 3) streamline the regulations and procedures for most efficient and uniform administration, operation, and industry compliance.

D. Other Mitigatory Measures

1. Special Stipulations

Leases for oil and gas exploration and development are subject to all OCS operating regulations and orders. Additionally, in some cases the lease may include special stipulations which are considered necessary for the protection of a particular resource, or activity, such as the one presented in Part B. above. These stipulations can be designed to meet the needs of a particular resource, e.g., wildlife or waterfowl refuges, fishing areas, certain recreation areas, protection of archeological or historical values, etc., which might be quite sensitive to development of the lease. In this proposed sale, the following three stipulations are presented to help mitigate potential impacts on historical and archeological values, commercial fishing activities, and the ecology and unique study area of the Flower Garden Banks offshore Texas:

(1) It is proposed that the following stipulation be applied to any lease resulting from this proposed sale for the protection of historical, archeological, or architectural values:

The lessee agrees that, prior to any drilling activity or the construction or placement of any structures for exploration or development (including, but not limited to well drilling and pipeline and platform placement), it will conduct sufficient geophysical studies to ascertain the possible existence of any sites, structures, or objectives of historical or archeological significance and if the Supervisor determines there are indications of the presence of such significant features, it will utilize the services of recognized professional underwater archeologists to study and, if necessary, survey the immediate area of the OCS to be affected by such activity, construction, or placement of structures in order to discover any site, structure, or object of historical, architectural, or archeological significance (all of which such sites, structures, or

objects are hereafter in this stipulation included in the term "cultural resource"). Upon completion of such study or survey, and before drilling, construction or placement of structures for exploration or development begins, the archeological study or survey report shall be forwarded to the Manager, New Orleans OCS Office, Bureau of Land Management, and to the Supervisor. Should the archeological report indicate that no cultural resource exists or is likely to exist in the immediate area to be affected by exploration or development activity, such activity may proceed. Should the archeological report indicate that a cultural resource does exist, the Manager shall consult the National Park Service concerning its disposition. Where possible, and subject to the Supervisor's approval, exploration and development activity shall be conducted with every reasonable effort to avoid the disturbance of cultural resources so identified. Where disturbance is unavoidable, the lessee shall utilize the services of recognized underwater archeologists to arrange for the salvage recovery of data and materials before exploration or development commences. While such archeological study or survey and salvage procedures should result in the identification of all cultural resources prior to drilling, construction, or placement of structures, it is agreed that, if any cultural resource should be accidentally discovered after the completion of the archeological study or survey and salvage, the operator in charge of any activity related to OCS oil and gas exploration or development, including, but not limited to, well drilling and pipeline and platform placement, shall immediately report such findings to the Manager, New Orleans OCS Office, Bureau of Land Management and to the Supervisor and shall make every reasonable effort to preserve and protect the cultural resource from damage. The Manager shall consult the National Park Service concerning the disposition of the cultural resource discovered, including, if appropriate, salvage recovery of data and materials by archeologists.

- (2) In addition, a stipulation will be applied to any lease resulting from this proposed sale, the effect of which will be as follows:

Structures for drilling or production, including pipelines, shall be kept to the minimum necessary for proper exploration, development, and production and to the greatest extent consistent therewith, shall be placed so as not to interfere with other significant uses of the Outer Continental Shelf, including commercial fishing. To this end, no structure for drilling or production, including pipelines, may be placed on

on the Outer Continental Shelf until the Supervisor has found that the structure is necessary for the proper exploration, development, and production of the leased area and that no reasonable alternative placement would cause less interference with other significant uses of the Outer Continental Shelf including commercial fishing. The lessee's exploratory and development plans, filed under 30 CFR 250.34, shall identify the anticipated placement and grouping of necessary structures, including pipelines showing how such placement and grouping will have the minimum practicable effect on other significant uses of the Outer Continental Shelf, including commercial fishing.

(3) To avoid conflict with present uses of the Flower Garden Banks as a unique study area and potential future use as a marine sanctuary (see figs. 24, 25, 26, 27, 48, 49), a stipulation will be applied to Tract Nos. 219, 220, 227, 228, 229, 231, 232, 239, 240, and 241. (and possibly 214 and 215, which may contain part of the West Flower Garden Bank; this will be identified by the Coast Guard - Geological Survey bathymetric profiling currently being conducted), in the event they should be leased, the effect of which will be as follows:

No structures, drilling rigs, or pipelines will be allowed within the aliquots established for the East and West Flower Garden Banks (see figs. 48 and 49, Vol. 1 for tentative aliquots which may be revised pending results of a Coast Guard - Geological Survey bathymetric profiling of the banks which is currently being conducted). No structures, drilling rigs or pipelines will be allowed within 1 mile of the 25 fathom isobath around live reef-building corals.

Operations in the zone 1 to 3 miles from the 25 fathom isobaths around live reef-building corals on both East and West Flower Garden are restricted as follows. Drill cuttings and drilling muds must be disposed of in one of two ways: 1) shunting the material to the bottom through a downpipe that terminates 20 feet or closer to the bottom and where the water depth above the outfall is 300 feet or

more, or 2) barging the material a minimum of 10 miles from any 25 fathom isobath surrounding live reef-building corals before disposal. Should barging be the method selected, disposal sites must be approved by the Area Supervisor, USGS, and any agency having jurisdiction at the time.

No garbage, untreated sewage, or other solid waste shall be disposed from vessels (work-boats, crew-boats, supply boats, pipe-laying vessels) involved with exploration and development operations within the area on each bank bounded by a line three miles from the 25 fathom isobath around live reef-building corals.

No drilling permits will be issued by the Supervisor until he has found that the lessee's exploration and development plan filed under 30 CFR 250.34 is adequate to insure that exploration and production operations in the leased area will have no significant adverse effect on the biotic community of high value reef sites on the Flower Garden Banks. As a part of the development plan, a reef monitoring program must be included. The monitoring program will be designed to assess the effects of oil and gas exploration and development operations on the viability of the coral reefs. The development plan should indicate that the monitoring program will be conducted by qualified independent scientific personnel and that program personnel and equipment will be available at the time of operations. The monitoring team will submit its findings on an interim on-going basis, or immediately in case of imminent danger to the reefs resulting directly from drilling or other operations. To further aid the Supervisor in his findings, he shall request reports on potential effects and recommended measures that may be necessary to prevent or mitigate the effects from the Manager, New Orleans OCS Office, Bureau of Land Management, and the Regional Director, Bureau of Sport Fisheries and Wildlife, Albuquerque, New Mexico.

The stipulation above is a result of several meetings with concerned parties at the Federal, State, industry and scientific and academic levels, as well as public oral and written testimony concerning the proposed sale in general and the possible development near the Flower Gardens specifically. Several points have been raised which are not found in the stipulation, but are covered by other regulations or operating orders. These are indicated below, in order to emphasize awareness of potential problems and strict adherence to the pertinent regulations.

Methods of garbage (solid waste) disposal from platforms are outlined in OCS Order No. 7, Section 1.B. (2), which indicates these materials must be incinerated or transported to shore. The OCS Operating Orders are included as Attachment A.

Methods and limitations on sewage disposal from all platforms, fixed and mobile structures, and artificial islands are contained in OCS Operating Order No. 8, Section 2.A.9. (Attachment A).

Normal operations for solid waste and sewage disposal are outlined in Section III. A.3.e. of the impact statement.

The use of oil spill dispersants (emulsifiers, sinking agents) is prohibited by Annex X of the Regional or National Oil and Hazardous Substances Pollution Contingency Plan (see Section V. A.4.b. of the

Final Environmental Statement), except for safety reasons in exceptional cases. This prohibition follows from the fact that many of these dispersants are inimical to aquatic life, and, since the reefs are at least 50 feet deep, the sinking or emulsification of oil would be more hazardous than allowing the oil to float over the reefs and degrade naturally.

The reef monitoring program required in the development plans for specific tracts around the Flower Garden banks is another device for ensuring the protection of the highly valued coral reefs. The program should primarily employ visual monitoring techniques (photographs, underwater television, direct diver observation) to assess any suspended sediment reducing water clarity, any sediment deposition on live reef-building corals, point sources of deleterious discharges, or other indications of detrimental effects that may be caused by oil and gas operations. The program should be designed for maximum intensity of observation during exploration or development drilling, and in the zone from one to three miles from the 25 fathom contour around thriving coral reefs. The level of effort may be reduced as distances from this zone increase, and during producing (non-drilling) operations. The possibility of testing various monitoring techniques should be explored. Stetson Bank, in Blocks A-502 and A-513 of High Island, South Addition, would be an ideal site for such testing, as the bank harbors a reef-type

community and live (but non-reef-building) corals. These blocks have been leased in a previous sale, but exploration and development have not yet begun. Exploration and development of Stetson Bank should occur long before such activities commence at the Flower Garden Banks.

The monitoring team shall consist of qualified scientific personnel not connected with any tract lessee or subcontractor of any tract lessee, and will submit interim reports of its findings. Specific support needs of the team at sea will be negotiated between the monitoring team and the tract lessee.

The portion of the stipulation concerning disposal of garbage, untreated sewage, and other solid wastes from vessels was added because disposal from vessels does not appear to be covered in the OCS Operating Orders. These materials could seriously degrade the reefs for various reasons. One of the primary fears of scientists is that these materials may attract larger numbers of sharks to the area, possibly upsetting ecological balance and posing a hazard to scientific research personnel.

2. Notices to Lessees and Operators

These notices have the same effect or status as OCS Operating Orders and Regulations and are used when expeditious clarifications or corrections and additions to existing orders and regulations are necessary. By issuing Notices to Lessees and Operators, the extensive amount of time necessary to amend and republish orders

and regulations is avoided. One example of a Notice, issued December 11, 1972, explains and details conditions of approval for waste water (oil field brines) disposal from OCS wells at offshore facilities. This Notice provides that such discharges shall meet applicable Federal Environmental Protection Agency or State standards for effluent limitations, whichever are more stringent, and provides for certain monitoring activities. The recent ban on offshore use of PCB's was also implemented by such a notice.

3. Departures

A departure (waiver) from OCS orders or other rules of the GS Supervisor may be granted when such a departure is determined to be necessary for (30 CFR, 250.12(b):

- a) the proper control of a well,
- b) conservation of natural resources,
- c) protection of aquatic life,
- d) protection of human health and safety,
- e) protection of property, or
- f) protection of the environment.

Waivers are technically based decisions and are granted in situations only where expert judgment determines that better, safer operations would result from operations under the waiver.

4. Research on Advanced Technology

EPA and Coast Guard are conducting research on more efficient containment and recovery devices (booms and skimmers). The efficiency of booms and skimmers depends on sea state and spill conditions but in any case are never 100% efficient. When the results of these studies, and any other similar studies so indicate, the requirement for use of better techniques and equipment will be incorporated into the OCS regulations and orders as appropriate. If incorporated, the requirements will be applied to all leases.

5. Geophysical Considerations

a. Geophysical Information

The Conservation Division of the Geological Survey is aware of the near-surface structural configuration and its effects on drilling, fixed-structural emplacements, pipelines, etc., relative to the proposed lease tracts. Knowledge of near-surface structural conditions is fundamental to a sound lease management program for the OCS.

Geophysical data, which show the shallow structural and sedimentary environment, are used to predict, and thus minimize, any geologic hazards to drilling operations and consequent possible dangers to the environment, from pollution. Surface and shallow subsurface geologic hazards, when properly identified and correlated with surrounding strata, seldom create insurmountable obstacles to a minimal risk program of exploration and exploitation of economically attractive structures.

High-resolution geophysical data covering all tracts to be offered for sale will be purchased by GS and analyzed by GS geophysical personnel. These data, in the area of coverage, provide definitive information on (1) thickness of the unconsolidated sediments (0-300'); (2) structural configurations on shallow seismic horizons (300-1500) feet below ocean bottom; (3) sea floor anomalies, mud mounds, mud waves or potential slide areas, pipeline and other objects on the sea floor, and borehole locations as interpreted from a combined analysis of several geophysical measurements, and (4) bathymetry.

Information from these high resolution data are extremely useful in detecting shallow geologic hazards such as potentially unstable bottom conditions (mud waves, etc.), shallow faults, and in some cases, near-surface gas pockets. When these features are identified prior to drilling operations, or platform construction, the operator is notified so he can take the necessary action to assure that his operation is conducted with maximum safety.

Interpretations of high resolution bottom profile data, that will disclose bottom and subsurface conditions posing special environmental hazards for drilling or producing operations in the Texas offshore area, will be made available to the Bureau of Land Management prior to the decision to issue a lease, and to the Geological Survey prior to the approval of drilling operations. 1/

1/ The District Engineer, Geological Survey, will prohibit the placement of platforms on areas of instability should the need arise through his authority to issue or not issue permits for platform placement.

b. Flower Garden Banks

The Flower Garden Banks, located over two piercement salt domes near the edge of the continental shelf in the northwest Gulf of Mexico, are capped by living coral reefs and typical Caribbean reef communities. They are the most prominent of a series of topographic highs in the northwest part of the Gulf of Mexico, and are located approximately 110 miles SSE of Galveston, Texas, in the High Island Area, East Addition, South Extension. The West Flower Garden Bank is located on a portion of Blocks A-384, A-385, A-397, A-398, A-399, A-401, and N638-E87. The East Bank is located in Blocks A-374, A-375, A-388, and A-389. The reefs probably formed at a time of lowered sea level, and through reef growth and/or salt uplift have survived the latest rise in sea level.

The West Flower Garden Bank is a northeast-southwest elongated expression, over seven miles long and four miles in diameter on the sea floor. The crest of the living coral reef is approximately 65 feet below the surface of the water. East Flower, Garden Bank is a somewhat smaller, sharper bank whose reef crest is approximately 55 feet below the surface. Fathometer profiles across the bank show rugged and sharp features of coral heads. Both of the features rise from a water depth of approximately 400 feet on the south flank and 325-350 feet on the north (landward) flank.

6. Conservation Practices

The Oil and Gas Supervisor, in the interest of conservation, is authorized pursuant to the Code of Federal Regulations,

to approve well locations and well spacing programs necessary for proper development giving consideration to such factors as the location of drilling platforms, the geological and reservoir characteristics of the field, the number of wells that can be economically drilled, the protection of correlative rights, and the minimizing of unreasonable interference with other uses of the Outer Continental Shelf. The Supervisor draws his authority from the following regulations and OCS operating orders:

30 CFR 250.11 outlines in broad terms the Supervisor's authority to control development of the OCS, to protect the environment, and to obtain maximum economic recovery of mineral resources under sound conservation practices.

30 CFR 250.17 dealing with well spacing authorizes approval of well locations, platform locations, and lists factors for consideration in this regard.

30 CFR 250.30 requires lessee's compliance with OCS Orders as well as general regulations and demands all necessary precautions to prevent damage, waste, and injuries.

30 CFR 250.34 requires the lessee to submit to the Oil and Gas Supervisor exploratory drilling plans, lease development plans and applications for permits to drill prior to these drilling programs. The Oil and Gas Supervisor utilizes well information such as electric well logs, core information from other wells

previously drilled in the vicinity of the proposed drilling program and geological and geophysical data and other pertinent reservoir information to determine the proper number of wells necessary for development.

30 CFR 250.50 grants the Director authority to demand pooling or unitization which the Secretary is authorized to require under the OCS Lands Act in the interest of conservation.

30 CFR 250.51 refers to the unit plan regulations 30 CFR 226 in regard to obtaining approval of units or cooperative agreements.

30 CFR 250.52 lists purposes for which the Supervisor may approve pooling or drilling agreements.

30 CFR 250.16 authorizes the Supervisor to specify the permissible production of a well. Thereafter, OCS Order No. 11 establishes the production rate control at the Maximum Efficient Rate (MER) of the well or reservoir. MER is defined in OCS Order No. 11, see Attachment A.

7. Other Requirements

In addition to the Interior Department's requirements, the operator must comply with applicable navigation and inspection laws and regulations administered by the U.S. Coast Guard. These

relate to safety of personnel and display of prescribed navigational lights and signals for the safety of navigation. Permits to install islands and fixed structures and the drilling of wells from mobile drilling vessels must also be obtained from the U.S. Army Corps of Engineers, which is authorized by the Outer Continental Shelf Lands Act to prevent obstruction to navigation. The decision as to whether a permit will be issued by the Corps of Engineers is based on an evaluation of the impact of the proposed work on the public interest. Factors affecting the public interest according to the Corps of Engineers include, but are not limited to, navigation, fish and wildlife, water quality, economics, conservations, aesthetics, recreation, water supply, flood damage prevention, ecosystems, and, in general, the needs and welfare of the people. Pipeline construction must also be in compliance with standards established by the Office of Pipeline Safety, Department of Transportation. The Department of Labor establishes Occupational Safety and Health Standards which are applicable to OCS operations.

Operators must comply with requirements of the Federal Water Pollution Control Act Amendments of 1972 (P.L. 92-500; 86 Stat. 816) which establishes a National Pollutant Discharge Elimination System, 40 CFR Part 125, 38 F.R. 13528 (1973). This system applies to discharges on the Outer Continental Shelf from any point source and requires any person to obtain a permit from the EPA for the discharge of any pollutant as defined by the Act. Discharges of any pollutant without

the necessary permit from EPA is made unlawful by the Act. Pursuant to section 501(b) of the Act, the Department of the Interior has suggested to EPA that the feasibility of a memorandum of understanding between the two agencies be considered in order to facilitate the administration of the NPDES as it applies to discharges arising from OCS lease operations and to minimize any redundancy of efforts by the Geological Survey and EPA.

VI. UNAVOIDABLE ADVERSE ENVIRONMENTAL EFFECTS

As described in Vol. 1, Sec. III. B. of this statement, certain features of oil and gas operations cause adverse effects which may be considered unavoidable in the light of current operation practices, technology, and regulations. A capsule summary of the significant effects from this sale are identified below. In addition, although oil spills resulting from this proposed sale can in general be avoided, some of the effects of an oil spill, if one should occur, are considered unavoidable and are also discussed below.

A. Effect on Marine Organisms

Several oil and gas operations result in temporary increases in turbidity. These operations include the discharge of drilling fluids and the excavation of pipeline trenches by jetting and dredging. When turbidity is generated near the water surface, the depth of penetration of sunlight is diminished. This leads to a decrease in the output of the photosynthetic mechanism of the phytoplankton. The dimensions of the area affected are small and consist of a plume hundreds of yards in length. The duration of the turbidity in a given location will be several hours if the source is pipeline burial operations, and several weeks to several months if the source is drilling fluid discharge. The effect of any decrease in primary production must be considered adverse. The area involved is very small and any reduction would only occur locally and would not involve the entire population of marine organisms.

Clogging of respiratory surfaces and filter-feeding mechanisms could reach a severe level in the benthic animals, however. The result of turbidity will be physiological stress, and possible mortality. This impact will be encountered during pipeline jetting operations and will be restricted to the downstream direction of the ocean current. The duration of the impact in a given area will be no longer than a few hours, but if it occurs in shellfish beds and similar concentrations of organisms the impact would be considered adverse.

Beneath every platform where wells have been drilled is an expanse of cuttings, released during drilling, which has buried and smothered all non-motile benthic forms below it. If it is different in texture and composition from the surrounding sediment, it will not likely be colonized by local forms.

Exposure of biota to harmful or toxic materials released into the marine environment or coastal marsh such as from accidental spills of crude oil, fuel and solvents, and the routine discharge of formation waters will bring about an adverse effect if this occurs. The effects of heavy concentrations of crude oil and petroleum derivatives, depending on their composition, consists of lethal toxicity, sublethal effects, coating with weathered oil, behavioral changes, and habitat changes. The more subtle effects of light contamination may be serious also, but are not well understood at this time. Some specific types of this effect are:

1. Marine phytoplankton have been shown to suffer stress and mortality when exposed to oil during laboratory experiments.

2. Copepods have been found ingesting and passing oil droplets without apparent harm. The copepods, however, serve as an important link in the food chain between phytoplankton and larger animals and ingested hydrocarbons are therefore passed on to larger organisms.

3. All marine plankton present near the core of the plume of formation water, before it is sufficiently diluted by sea water, will suffer stress or mortality from concentrations in the plume. This adverse effect will be immeasurably small at the population level.

4. Laboratory experiments show that fish may be killed during the egg and larval stage after exposure to crude oil. Respiratory surfaces become clogged and damaged in juvenile and adult stages. These effects would occur if spills come in contact with eggs and larvae in the breeding zones.

5. In the event of an onshore oil pipeline leak or spillage on onshore facility, vegetation would be affected according to the severity of the spill. A small leak may do little damage. A severe leak however, may contaminate the substrate and kill the vegetation that comes into direct contact with the oil and several years may be required for recovery. Small animals in contact with the oil would likely be killed.

6. Although large numbers of bird deaths have not been a feature of past oil spills in the Gulf of Mexico, the probability is high that if a large spill comes ashore in the western Gulf, that large numbers

of shorebirds, wading birds, and waterfowl will be killed-- an exceedingly adverse impact.

Although the potential for harm is present, the inability to predict accidental oil spills makes an assessment of the scope of the effect on birds uncertain.

Damage to immobile, attached, and rooted organisms during excavation and reworking of sediments and soil, and suspension of sedimentary materials can occur from entrenching of subsea pipelines, burial of pipelines through beach and where applicable, adjacent coastal wetlands. During emplacement of subsea pipelines, sediments and benthic animals are washed out by hydraulic jetting. Softer life forms are likely killed, others are made vulnerable to predation, and in immediately adjacent areas of down stream ocean currents, some burial and smothering could be expected. The effect is limited to local areas around drill holes and pipeline paths. In these areas, the effect is adverse and unavoidable.

B. Wetlands and Beaches

If an oil spill impacts upon a beach then there will be an adverse effect, which may last from weeks to several years or more, depending on the amount of oil and size of the area impacted. Heavily contaminated beaches will be rendered unsuitable for recreation so long as they remain contaminated with oil. If mechanical means are employed in beach clean-up operations (bulldozers, front end loaders and other earth moving equipment) as was done following the Santa Barbara and Arrow oil spill incidents then shoreline equilibrium may be upset by beach removal. Excessive removal of beach materials can lead to erosional problems unless enough sand and gravel, for example, are available to replace the removed beach materials.

C. Deterioration of Air Quality

Air quality will not be seriously impaired by routine operations, however, degradation could result from several types of accidents.

In a natural gas leak or gas well blowout degradation would be small; air pollutant would be mostly methane which quickly volatilizes and drifts away. If a fire results, pollutants would be largely carbon dioxide and water vapor.

Oil leaks and oil spills not accompanied by a fire, produce pollutants of lighter ends, i.e., more volatile components of crude oil. Their degree of degradation is unknown, but resultant photochemical smog is a possibility. If the spill results in a fire, large amounts of particulate carbon, and oxides of carbon, along with smaller but

unknown amounts of sulfur oxides, nitrogen oxides, evaporated crude oil liquids, and partially oxidized compounds, would enter the air. Local air quality would be severely degraded during the period of the fire. This effect, should a fire occur, would be considered adverse and unavoidable.

D. Deterioration of Water Quality

Degradation of water quality by routine operations will be minimal. Brines added to sea water quickly diffuse through the water column.

Moderate to severe degradation would occur however in the event of an accidental oil leak or spill. The effects of water quality degradation on the biotic community would be the major concern if this occurred. As with all accidents the uncertainty exists, but were it to occur, the effect would be adverse. In addition, water quality degradation will occur onshore if produced waste water is transported to shore for treatment and then discharged into fresh or brackish water systems and operators fail to follow waste water quality standards.

E. Interference with Commercial Fishing Operations

As described in earlier sections, trawling operations suffer interference and inconvenience from oil and gas operations in several ways. A small portion, up to 0.3% of each tract leased, of sea floor is occupied by drilling rigs and platforms and is unavailable to trawl fishermen. Based on past exploration success rates, up to 1,150 acres of sea floor may be occupied by platforms resulting from this proposed

sale. Trawling nets reportedly become entangled on underwater stubs and unburied pipelines, causing damage or loss of the nets. Less frequently, large objects lost overboard off petroleum industry boats and platforms are caught in trawling nets, damaging the net or its catch of fish. The frequency of occurrences of this nature is unknown.

Although commercial fishermen could be expected to avoid the area of an oil spill, spilled oil could coat or contaminate commercial fish species, rendering them unmarketable. This would be another adverse effect to commercial fishing.

F. Interference with Ship Navigation

Very little interference can be expected between drilling rigs and platforms and ships that are utilizing established fairways. However, at night, and especially during rough weather, fog, and heavy seas, ships not navigating the fairways could collide with fixed structures. Also fishing boats engaged in trawling will be inconvenienced by having to navigate around fixed structures located on fishing grounds. Based on past exploration success rates, up to 275 new platforms could result from the proposed sale. Added to the 2,000 platforms now in the Gulf of Mexico the increment is small but still represents a potential increase in possible interference with shipping.

G. Damage to Historical and Archeological Sites, Structures, and Objects

During excavation ferrous objects above a certain size will be detected by magnetometer surveys of proposed pipeline routes. Other as yet undiscovered sites, objects, or structures not detectable by such surveys will probably be damaged if they are in the path of pipelines. These sites, structures and objects can be located on the continental shelf as well as onshore. The incidence of this occurrence is considered to be low. Were it to occur it would be considered to have an adverse effect.

Other damage to archeological resources could come from oil contamination. Historical and archeological materials soiled by an accidental oil spill may not survive subsequent cleaning and restoration efforts. Porous materials could be rendered unsuitable for carbon dating techniques. The uncertainty that such a polluting event will occur is large and the potential for significant resource destruction appears small, although it does exist.

H. Interference with Recreational Activities

Interference with recreation is closely related to degradation of aesthetic values. Oil contaminated beaches, freshly cut pipeline route terminals and other onshore support facilities would normally be avoided by those seeking recreation sites for use or development. Disturbance of beaches by pipeline burial operations will be very short-lived, relative to recreational use. Oiled beaches may require days, weeks, or years for adequate restorations if they become damaged. The uncertainty of accidental spills is applicable to this event also, but if spilled oil ever reached the beach it would have an adverse effect on recreational opportunities.

I. Degradation of Aesthetic Values

Platforms and drilling rigs on four tracts included in this proposal and located between 13 and 17 miles from Galveston Island and Bolivar Peninsula will be visible to the naked eye of a mainland viewer. A few onshore pipeline terminals and treatment facilities will be constructed as a result of this proposed sale. If these objects interfere with residential or recreational vistas, the visual effect would probably be considered adverse. The incremental addition to what exists in the region is small, however. The effect, therefore, is considered small.

Spilled oil and debris floating in the water or washed up on the beach would also severely detract from the scenic values of any local area. Considerable uncertainty attaches to this possible effect. Before the

natural terrain and vegetation has been completely restored, the effects of pipeline burial will appear as a large scar traversing the beach and coastal lands. Restoration over most of the scar will require at least one year. This latter effect is important only in the two vicinities where new pipelines may cross the shore area and although temporarily adverse it is generally of minor significance.

J. Conflict with Other Uses of the Land

Small amounts of land, during the laying of pipeline and the construction of pipeline terminal or other onshore facilities if located in agricultural areas will be temporarily lost for grazing or farming purposes. Interruption until the following growing season usually results. The existence of pipeline terminal facilities and a gas separator facility will involve the permanent loss of anywhere from one to an estimated 48 acres for grazing or farming, because each facility usually is enclosed by a fence. A pipeline leak, however, involving the release of oil into farm land would render the land contaminated and unsuitable for grazing or other agricultural purposes. One to several growing seasons might be required for recovery of affected vegetation and degradation of spilled oil. The low probability of this effect and the relatively small areas involved indicate it is minor, although were it to occur it would be considered adverse.

VII. RELATIONSHIP BETWEEN LOCAL SHORT-TERM USE AND MAINTENANCE AND
ENHANCEMENT OF LONG-TERM PRODUCTIVITY

The principal short-term use of the proposed sale area will be the extraction of oil and gas from those tracts which prove economically productive. This mineral extraction will contribute to the diminishment of the long-term productivity of the non-renewable oil and gas resources of the Gulf of Mexico and possibly to marine and coastal resources.

To date, there has been no discernable decrease in marine productivity in OCS areas where oil and gas have been produced for many years. Concern has been expressed regarding the possibility of long-term reduction in productivity of the overall ecosystem resulting from continued oil and other discharges being spilled into the water.

The possibility that the implementation of the proposed lease sale together with existing production on the Outer Continental Shelf might sacrifice the long-term productivity of the area to the short-term use of non-renewable mineral resources must be recognized even though the long-term effects of oil spillage into the environment are not clearly understood at this time.

The additional stress which the ecosystem can absorb is limited, but at present, the bounds of these limitations are not known. St. Amant observes, " Certainly the significance of the continual addition to and accumulative effect of sublethal pollutants in the environment is probably the most important ecological question facing us today." 1/

1/ St. Amant, Lyle S., "Biological Effects of Petroleum Exploration and Production in Coastal Louisiana," Louisiana Wildlife and Fisheries Commission, December 1970. p. 20.

It is not anticipated that other impacts caused by oil and gas operations will decrease either short-term or long-term productivity in the ocean.

Disturbance of coastal land by pipeline construction and burial operations and construction of related onshore facilities will decrease productivity in the short-term. Useful productivity of coastal lands in the area disturbed by pipeline operations will decrease following the disturbance and will rise to natural levels as original conditions are restored in subsequent growing seasons. Light grazing or farming pressure most likely will not have any effect, but heavy grazing or farming could serve to keep the disturbed areas from recovering at an optimum rate. Species diversity in the disturbed area will be low during the recovery period.

Based on past leasing and exploration experience, as many as 160-275 new platforms will be emplaced as a result of this proposal.

The cumulative affect of structures on multiple-uses in offshore areas where more and more structures are required as OCS production increases is one of concern. The cumulative nature of structures as hazards to commercial shipping and as obstructions to commercial fishing activities represents a use conflict that can be controlled through proper planning and coordination with appropriate Federal and state agencies and private industry. Some leveling out in overall numbers of platforms in the Gulf of Mexico is expected as more and more areas decrease or go out of production and platforms are removed. This same feature is

also expected with regard to the cumulative numbers and length in miles of pipelines to shore. In the case of pipelines, as more and more areas begin to approach termination of production, some additional capacity will be available in existing pipelines to carry production from new areas thereby reducing the numbers of new pipelines required to move production to shore. We are unable to determine at this time if the total number of platforms and pipelines required to develop the OCS areas in the Gulf of Mexico has peaked but indications are that conditions are approaching a leveling off point.

A particular area of concern is expressed with regard to the petroleum industry's impact in the marshlands of Louisiana. There is convincing scientific evidence that their activities, associated with oil and gas production in the marshlands, have contributed to marsh destruction and land loss that could very well prove to decrease the long-term productivity of the area for the short-term use of minerals extraction. This matter is being closely monitored by scientists from Louisiana and others. The single most damaging activity associated with the petroleum industry's operations in the marshlands is the construction of rig access canals. This feature is not associated however, with oil and gas production activities on the Outer Continental Shelf and therefore can be eliminated from consideration as a potential adverse impact resulting from OCS operations. The construction of onshore facilities and pipeline canals in or through marsh areas, however, does represent a potential source of impact ancillary to, but associated with, OCS production. The potential for a decrease in long-term productivity

resulting from onshore activities related to OCS operations is present and should be given careful consideration by state and local authorities before approving or denying the use of their marshlands for such purposes.

From the information at hand, long-term productivity of the Gulf environment, we believe, is not being reduced by oil and gas activities on the Outer Continental Shelf.

VIII. IRREVERSIBLE AND IRRETRIEVABLE COMMITMENT OF RESOURCES

A. Mineral Resources

The leasing of the proposed tracts in this sale would permit development and extraction of the leasable minerals. This lease sale could result in an estimated range of production of 50-100 million barrels of oil and 6-11 trillion cubic feet of gas which would represent an irreversible and irretrievable commitment of mineral resources.

B. Land Resources

Industry has estimated the need for 1 gas and possibly 1 oil pipeline to shore to develop the estimated reserves from this proposed sale. In connection with these pipelines, approximately 1 new onshore production terminal station, and 1 gas separator facility will be constructed. This construction would involve the irretrievable commitment of approximately 48 acres of coastal lands for station or facility sites. Physical removal of habitat representing an irreversible and irretrievable commitment of a resource on which fish and wildlife rely will occur in the area required for construction of pipeline terminals and storage and pumping facilities.

C. Fish and Wildlife Resources

An irreversible or irretrievable commitment of fish and wildlife resources and their habitats could occur in the area of a massive oil spill or if frequently subjected to chronic low levels of oil pollution. At this time, there is insufficient evidence to

conclude that low level spillage has led to an irreversible commitment of fish and wildlife resources but there is enough evidence to indicate that this is a possibility that deserves close attention, and constant study.

An irreversible or irretrievable commitment of habitat in the area required for construction of pipeline related support facilities, estimated at 48 acres, will occur if this sale proceeds. This could have an irreversible or irretrievable synergistic effect on any fish and wildlife dependant upon the habitat in the construction area.

X. ALTERNATIVES TO THE PROPOSED ACTION

A. Hold the Sale in Modified Form

1. Details of Tract Selection Process for Proposed Texas Sale

The Texas call for nominations resulted in approximately 3.8 million acres being nominated by 40 companies out of about 12.5 million acres available. The tract selection process sets forth an orderly, systematic procedure by which the 3.8 million acres were reduced to a logical, reasonable sale size (average over 1,000,000 acres). Approximately 1,355,000 acres were selected to attempt to assure full compliance with the President's Energy Message directing increased OCS leasing.

Three primary leasing objectives or Departmental goals have been established for the OCS program. These objectives are: orderly resource development, protection of the environment, and receipt of fair market value. These three objectives are necessarily broad, but require specific application in the tract selection process.

a. Nominations and Past Leasing History

The weighed nominations, history, and other pertinent data were reviewed by the BLM New Orleans Office. The nominations were analyzed to identify implied geologic structure, the history analyzed to determine if interest in specific tracts had increased, lessened or was the same as to nominations received in the past.

b. Geology

On October 10, a meeting was held between BLM New Orleans and GS Metairie to discuss tracts which BLM has previously

identified to GS as initial recommendations. GS had reviewed the tracts using available geological and geophysical data.

In the great majority of cases their data confirmed the initial recommendations as determined by analysis of nominations.

In cases where there appeared to be a difference between interest, as expressed by nominations, and GS data, specific structural maps which GS had available for the proposed sale area were reviewed. These maps, for the most part, consisted of small scale composite structural maps (approximately 1" to 3 miles). Also, specific wells which potentially affected some of these blocks were discussed as to amount and type of production, if any. In some cases where larger scale field maps were available (approximately 6" to 3 miles), these were also used by GS in their presentation to BLM.

c. Environmental Considerations

The preliminary environmental analysis was presented in the general form of physical, resource and socio-economic profiles, using map overlays and written documentations. The categories of information presented include:

1. Ocean currents and wind
2. Basic geology
3. Bottom sediments
4. Hazards
5. Outdoor recreation
6. Sport fishing

7. Commercial finfish
8. Commercial benthos
9. Commercial shrimp
10. Threatened species
11. Upland wildlife
12. Upland birds
13. Waterfowl concentrations
14. Livestock and grazing
15. Transportation
16. Lands and waters of ecological importance
17. Lands "suitable" for development
18. Socio-economic

The above basic information was then interpreted as to the potential impact on, or hazard to, the individual resource from offshore drilling and development, pipeline construction and oil spillage. From these interpretations "potential environmental hazard zones" were developed for use in the tract selection process.

d. Special Considerations

(1) Defense Warning Areas

No warning zones were identified which affected the area so no possibility of conflict between leasing and warning area uses was considered.

(2) Sales Size

Departmental guidelines, based on supply-demand and potential reserve estimates, have established approximately

1,000,000 acres as the average sale size. In response to the President's Energy Message the tracts selected in this case represent about 1.35 million acres which brings the average for the three proposed sales in this fiscal year to over 1,000,000 acres.

(3) Deepwater Tracts

Our selection of "deepwater" tracts (water depth over 120 meters) totalling approximately 340,000 acres is deemed appropriate within the tract selection guidelines.

All so called "deepwater tracts" selected are logical extensions of adjacent acreage in the older mapped area and should provide no insurmountable problems for exploration and production.

(4) Other

Consideration in tract selection was given to economic, including industry economics, national economics and regional economics.

The high industry interest in offshore Texas, measured by level of nominations, expressed industry's desire to explore and develop this area. Special attention was given to tracts receiving a large number of nominations because this is an indicator that several companies view these tracts as having economically feasible production potential. For this reason, the number of nominations received is always an important factor in tract selection.

The proposed leasing of Texas tracts is an item on the tentative five-year schedule. The schedule attempts to relate timing, size and

location of each sale to the projected national needs for hydrocarbons. Production from this area would, to an extent, lessen our import needs and thereby ease the balance of payments strain. As to the choice of specific tracts in the tract selection process, the objective of orderly resource development received high priority. An attempt was made to select desirable tracts over a large area so that if and when they are leased, our geologic information and knowledge of type and extent of production will be greatly increased for planning future sales.

The economic and institutional factors taken into consideration in the tract selection process for OCS Sale No. 34 are contained in the regional economic and land use profiles developed by the Regional Planner in the Division of Environmental Assessment. This treatment is a part of the environmental profiles developed for the entire Gulf of Mexico by the New Orleans Office.

Factors considered include regional refining and processing capacities and present production, transportation and processing facilities.

In summary the tracts selected for further consideration for leasing and analyzed for potential environmental impact in this statement are believed at this time to have the highest geologic potential for gas production, highest estimated reserves and offer the most efficient resource exploitation. The potential environmental impact of leasing these tracts has been previously described in this impact statement.

2. Sale Modification Alternatives

a. Delete Tracts

The proposed sale is composed of only those tracts estimated to be gas-prone. This reduces the potential hazard to the environment from possible oil pollution events. The primary affect of deletion of any of these tracts would be to decrease potential exploration and production.

Development of gas-prone tracts only will still require seismic exploration, exploratory drilling, construction of permanent platforms and pipelines, production well drilling, workovers, maintenance and repair work with the attendant potential adverse environmental impacts discussed in detail throughout this environmental statement for those activities. If some of the tracts are deleted, the overall importance associated with the activities above regarding the environment would be essentially the same as if all the proposed tracts were offered. However, the magnitude of potential impacts would be reduced and the cumulative impacts associated with quantities of waste water effluents and debris, and the numbers of platforms and pipelines required to develop a lesser number of tracts would be lessened. With this alternative the environmental effects of pipelines, as previously discussed, would apply, but fewer miles would probably be required.

Another alternative would be to delete tracts strictly on the basis of depth. If all tracts in water depths of 300 meters or beyond

were deleted, 11 tracts (63,360 acres) will be eliminated; if all tracts 200 meters and beyond are deleted, 21 tracts (112,646.64 acres) will be eliminated.

The environmental impact of this possible modification would be essentially the same as that discussed above concerning the offering of gas prone tracts only because the gas prone tracts all have a relatively low potential for environmental harm.

Tracts could be deleted which are identified by matrix analysis to have the highest potential for environmental harm.

The environmental impact of this possible modification would be essentially the same as that discussed above concerning the offering of fewer gas tracts.

The same principle for platforms would apply, that is, the environmental effects associated with offshore platforms would be the same as those previously discussed, but with the removal of any tracts from the sale would be less than originally proposed. In any case, the potential environmental impacts as discussed in Section IV of this statement also apply to this alternative.

Another potential modification of the proposed sale would be the deletion of the 10 tracts previously identified as being located in the area of the East and West Flower Gardens. (See Section IV.D.

of this statement.) It is estimated that this would result in a reduction from 1 to 2 billion cubic feet of recoverable gas reserves. The deletion of these tracts could inhibit the development of adjacent tracts if such deletion reduced or interfered adversely with the collective need for pipelines to serve that area. In any case, however, the elimination of potential adverse environmental effects associated with this proposed sale in relation to the Flower Garden Banks would result if the 10 tracts were deleted from the sale.

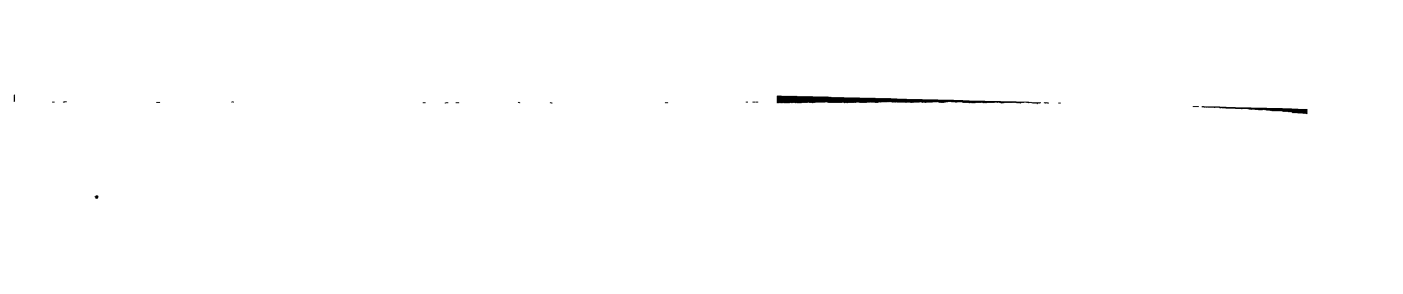
Mr. Robert Alderdice, Director of the Flower Garden Ocean Research Center, Marine Biomedical Institute of the University of Texas, testified at the public hearing on January 20, 1974, and recommended that 9 of the 10 tracts surrounding the Flower Garden Banks be deleted from the sale. The tenth block, A-389 to the southeast of East Flower Garden, would be offered and (presumably) leased. During exploration on this lease, an intensive monitoring effort would be mounted which would identify those parameters related to drilling which might have an impact on the reef areas. If little or no environmental harm came to the reef, the other 9 tracts could be offered at a later time.

b. Substitute Tracts

Tracts with relatively lower potential environmental risk could be substituted for those of high potential risk. Such

action would not necessarily result in less total activity or environmental effect since more acreage and blocks would be required to meet the minimum resource estimates. This would result in more exploratory drilling, more platforms constructed, additional miles of pipelines required and a substantial increase in production activities with attendant increase in potential adverse environmental impacts discussed in detail throughout this environmental statement for these activities.

In all probability, potential environmental benefits of substituting tracts with lower environmental risk and lower resource estimates may not be realized due to increased acreage and exploratory activity required.



B. Withdraw the Sale

In addition to modification of the proposed sale, all tracts could be withdrawn from leasing consideration. A decision to withdraw the sale completely or to seriously limit the number of tracts to be leased would diminish the contribution of OCS gas and oil toward future energy demand, and would subsequently necessitate development of alternative sources of energy, with their associated environmental impacts. These impacts are discussed in the assessment of possible alternatives on the following pages.

The projected production from the proposed sale would contribute significantly to domestic energy needs in the short run (5 to 15 years). Few alternatives exist to help offset the need for domestic oil and gas during this period. Research on alternatives for the long term is being accelerated, however. The status of research as well as the possible environmental impacts of these long term sources will also be discussed.

The following list of energy sources or actions, if fully implemented in the short run, might be considered as alternatives to offshore oil and gas.

1. Energy Conservation
2. Conventional Oil and Gas Supplies
3. Coal
4. Synthetic Sources of Gas and Oil
5. Hydroelectric Power
6. Nuclear Power
7. Energy Imports
8. Other Energy Sources
9. Combination of Alternatives

The approach used in analysis of each alternative has been to review the technology involved in realizing the energy from the source; the resource base of the energy inputs; economic considerations such as supply and demand schedules, cost and price projections, state of development; environmental impacts; and relationship of the alternative to the proposed OCS sale. This last section includes the amount required to replace the energy to be provided by the proposed sale. Limitations on the substitutability of the alternative for OCS oil and gas will also be discussed where applicable.

Some of these limitations include technology, high development and production costs, and time lag before the alternative could be a viable technical option. In early stages of development of an alternative source of energy, it may serve more as a supplement than as a substitute. Furthermore, there are some cases in which substitutability is diminished because of the projected use of the offshore oil and gas.

The discussion of these alternatives as presented below includes a consideration of the possibility of energy conservation as a method which might decrease or eliminate some of the energy requirements to be satisfied by this sale. A table has also been prepared showing the incremental production potential of the alternatives considered and the possibility of having a combination of sources substitute for the proposed sale.

The following table shows the equivalent which will be used in this discussion. When production has stabilized, the proposed Texas sale may result in 6,000-12,000 barrels of oil per day and 0.9-1.5 billion cubic feet of natural gas per day. Using common conversion factors, this level of production is first expressed in Btu's and then in terms of other important energy sources. The electrical equivalents were determined by considering two cases. The maximum requirement for generating capacity would result when the substitution of electrical energy for oil and gas occurred at the end use point. The minimum case is the result of substituting electrical energy produced by an alternative source for the electrical energy produced by the oil and gas.

Energy Needed From Other Sources to Replace The Expected Oil And Gas Production From The Proposed Texas OCS Sale #34

1. Btu Equivalents 1/ in billions of Btu's per day			
Oil -	6,000 to 12,000 bbl/day	= 34.8	to
Gas -	0.9 to 1.5 bill. cu.ft./day	= 228.8	to
		1548.0	
		69.6 billion Btu/day	
Total			
		963.6	to
		1617.6	
2. Oil Equivalents in barrels per day			
Oil from other sources needed to directly replace expected oil production from Texas sale #34			
	6,000		to
	12,000 bbl/day		
Oil from other sources needed to replace expected gas production from Texas sale #34			
	160,000		to
	267,000		
Total			
	166,000		to
	279,000		

1/ Conversion factors used:
 1 barrel of oil = 5.8×10^6 Btu
 1 cubic foot of natural gas = 1,032 Btu
 1 ton of coal = 24×10^6 Btu
 1 kilowatt hour = 3,412 Btu at the theoretical conversion rate of other energy forms to electricity at 100% efficiency.

3. Gas Equivalents in billions of cu.ft. per day

Gas from other sources needed to replace expected oil production from Texas sale #34

Gas from other sources needed to directly replace expected gas production from Texas sale #34

Total

Coal Equivalent in short tons per day and per year

Coal 40,150 to 67,400 short tons/day

5. Electrical Equivalents in thousands of megawatts of capacity

Substitute for end uses 1/ Substitute as input to electricity generation 2/

10.1 to 16.9 thousand Mw

5.5 to 9.3 thousand Mw

1/ Based on a 60% average efficiency of end use of oil and gas (such as oil and gas heating) and a plant load factor of 70%.

2/ Efficiency of fossil fuel electricity generation was assumed to be 33%.

1. Energy Conservation

The United States has both the highest per capita consumption of energy and the highest per capita income in the world. Energy has provided the foundation for a continued rise in our material standard of living. Demand for energy in the U. S. has been increasing at an average rate of 3.1% annually for the last twenty years, more than twice the growth rate of the U. S. population. Higher energy use per capita compounded by population growth has produced unprecedented levels of energy consumption. As population growth slows, increasing per capita demand will account for a larger and larger share of increasing total demand for energy. These trends are illustrated in Table I-12.

Table I-12: U.S. Total and Per Capita Net and Gross Energy Inputs

Year	Gross Energy Input qua- drillion Btu's	Net Energy Input	population millions	Gross Energy Input Per Capita million But's	Net Energy Input Per Capita million Btu's
1950	34.0	29.7	152.3	223.2	194.8
1955	39.7	34.3	165.9	239.3	206.7
1960	44.6	38.2	180.7	246.8	211.5
1965	53.3	45.3	194.2	274.4	232.1
1970	67.4	56.0	204.8	329.1	273.6
1975	80.3	65.1	216.2	371.4	301.2
1980	96.0	76.1	229.4	418.5	330.8
1985	116.6	89.7	243.3	479.2	369.9
2000	191.9	140.1	279.7	686.1	500.9

Source: United States Energy Through the Year 2000. USDI,
December 1972.

In the past, energy growth has been little constrained by price or by supply of resources. However, recognition that environmental costs should be reflected in price of energy, concern over environmental quality, and uncertainty of both immediate and long-term energy supplies have added urgency to the study and realization of energy conservation.

The shortage of oil, gas, and other energy sources in the past few years has been reflected in curtailment of deliveries under existing contracts, inability to secure immediate and assured long term supplies, denial of service to prospective new customers. The recent Middle Eastern Oil embargo further reduced energy supply.

The present energy crisis requires both development of domestic energy sources for immediate and long term needs, and extensive implementation of energy conservation programs. Conservation measures taken by the Federal Government in the past few months include: (1) passage by Congress of laws putting the Nation on daylight saving time (which started January 6, 1974) and reducing national highway speed limits to no more than 55 miles per hour, (2) creation of a Federal Energy Office to coordinate Government energy actions, (3) a major conservation program to cut use of energy by Federal agencies, and (4) a fuel allocation program.

The President, in a January 23, 1974, address on the energy crisis, outlined an extensive legislative program to meet short-term energy

imbalances and to promote long-term energy self-sufficiency. This program included: (1) establishment of a Federal Energy Administration, an Energy Research and Development Administration, and a Department of Energy and Natural Resources, (2) a special energy act that would permit restriction of the private and public consumption of energy and would temporarily relax certain Clean Air Act requirements for power plants and automotive emissions, and (3) legislation requiring all major appliances and automobiles produced or imported into the United States to be clearly labelled to indicate their energy use and efficiency.

Specific conservation measures and the savings they could achieve were listed in a Treasury Department report. 1/ The measures were divided into two categories: voluntary and mandatory. Most of the voluntary measures are expected to have a low level of compliance (10% to 15%). They include the following:

1/ Emergency Energy Capacity: An Interim Report, U.S. Treasury Department, Office of Energy and Natural Resources, Oct. 18, 1973.

Measure	Potential Annual Average Savings Equiv. B/D	Actual Savings Assuming 15% Compliance Equiv. B/D
reset thermostats 3°, summer and winter, 24 hours a day	550,000	82,500
insulate attics of all existing homes lacking adequate insula- tion	180,000	27,000
reduce electricity used for lighting	50,000	7,500
stop hot water use in clothes washing	180,000	27,000
stop use of clothes dryers	100,000	15,000
reduce energy consumption of commercial buildings by 10%	400,000	140,000 *

*The report assumes that actual savings in commercial buildings will be about 35% of the potential savings since compliance would be higher than for many other measures.

Among measures listed in the report that could possibly be implemented by mandate are:

Measure	Potential Annual Average Savings Equiv. B/D
increase by 1 the number of passengers in every commuting auto	780,000
reduce highway speed of autos, trucks, and buses to 50 mph	250,000
increase passenger load factor on aircraft to 65% from 50%	120,000

Increasing alarm over energy shortages and rising prices will encourage voluntary implementation of conservation measures. A recent ruling by the District of Columbia Public Service Commission authorized Potomac Electric Power Company (PEPCO) to charge increasingly higher rates to customers who use more than 400 kilowatt hours per month, but refused to allow a rate increase for customers who use less than 400 kilowatt hours of electricity. The Commission stated that it had "an obligation to do what we can to avoid unnecessary use (of electricity), but not penalize necessary and essential use". In some areas, rates have been changed so that large industrial users are charged higher rates than residential users.

The Office of Emergency Preparedness published a study on energy conservation in 1972. ^{1/} The study focused particularly on short-term and mid-term user conservation measures and did not consider improvements in recovery techniques for primary fuels or related government actions. The energy picture has changed considerably since publication of the study. However, the OEP study, one of the first comprehensive reports on energy conservation, contains guidelines which can be reevaluated in light of changed conditions. The measures suggested by OEP could reduce energy consumption by 1.0 quadrillion Btu (QBtu) a year in 1975, 15.5 QBtu a year in 1980, 33.4 QBtu a year

^{1/} The Potential for Energy Conservation. Office of Emergency Preparedness, October 1972.

Short-Term Measures (1972-1975)

Transportation - Conduct educational programs to stimulate public awareness of energy conservation in the transportation sector; establish government energy efficiency standards; improve airplane load factors; promote development of smaller engines/vehicles; improve traffic flow; improve mass transit and intercity rail and air transport; promote automobile energy-efficiency through low loss tires and engine tuning.

Savings - 1.9 QBTU/yr. 1/ (10 percent)

Residential/Commercial - Provide tax incentives and insured loans to encourage improved insulation in homes; encourage use of more efficient appliances and adoption of good conservation practices.

Savings - 0.2 QBTU/yr (1 percent)

Industry - Increase energy price to encourage improvement of processes and replacement of inefficient equipment; provide tax incentives to encourage recycling and reusing of component materials.

Savings - 1.9-3.5 QBTU/yr. (6-11 percent)

Electric Utilities - Smooth out daily demand cycle by means of government regulation; facilitate new construction; decrease electricity demand.

Savings - 1.0 QBTU/yr. (4 percent) (already assumed in the projections)

Mid-Term Measures (1976-1980)

Transportation - Improve freight handling systems; support pilot implementation of most promising alternatives to internal combustion engine; set tax on size and power of autos; support improved truck engines; require energy-efficient operating procedures for airplanes; provide subsidies and matching grants for mass transit; ban autos within the inner city; provide subsidies for intercity rail networks; decrease transportation demand through urban refurbishing projects and long range urban/ suburban planning.

Savings - 4.8 QBTU/yr. (21 percent)

Residential/Commercial - Establish upgraded construction standards and tax incentives and regulations to promote design and construction of energy-efficient dwellings including the use of the "total energy concept"

1/ Quadrillion BTU.

for multi-family dwellings; provide tax incentives, R&D funds and regulations to promote energy efficient appliances, central air conditioning, water heaters, and lighting.

Savings - 5.1 QBTU/yr. (14 percent)

Industry - Establish energy use tax to provide incentive to upgrade processes and replace inefficient equipment; promote research for more efficient technologies; provide tax incentives to encourage recycling and reusing component materials.

Savings - 4.5-6.4 QBTU/yr. (12-17 percent)

Electric Utilities - Restructure rates for heavy uses to smooth out demand cycle; facilitate new construction.

Savings - 1.1 QBTU/yr. (4 percent) (already assumed in the projections)

Long-Term Measures (beyond 1980)

Transportation - Provide R&D support for hybrid engines, non-petroleum engines, advanced traffic control systems, dual mode personal rapid transit, high speed transit, new freight systems, and people movers; decrease demand through rationing and financial support for urban development and reconstruction.

Savings - 8 QBTU/yr. (25 percent)

Residential/Commercial - Provide tax incentives and regulations to encourage demolition of old buildings and construction of energy-efficient new buildings; R&D funding to develop new energy sources (solar, wind power).

Savings - 15 QBTU/yr. (30 percent)

Industry - Establish energy use tax to provide incentive for upgrading processes and replacing inefficient equipment; promote research in efficient technologies; provide tax incentives to encourage recycling and reusing component materials.

Savings 9-12 QBTU/yr. (3 percent)

after 1980. These energy savings represent the maximum that could be achieved if all the suggested measures were implemented. Since many of the suggestions depend on voluntary cooperation for which incentive is slight, the estimates must be regarded as the upper limit and not the most likely outcome.

The OEP found the greatest potential for energy conservation in 1) improved insulation in homes, 2) adoption of more efficient air conditioning systems, 3) shift of intercity freight from highway to rail, intercity passengers from air to ground travel and urban passengers from automobiles to mass transit and freight consolidation in urban freight movement, and 4) introduction of more efficient processes and equipment.

The following outline of specific measures directed at the four major consuming sectors - transportation, residential/commercial, industry, and utilities is taken from the study. These measures could be implemented through standards and regulations, tax incentives, and educational campaigns.

To coordinate energy programs and carry out the directives of President Nixon's April 18, 1973 Energy Message, Secretary Morton of the Interior created three new offices on energy - the Office of Energy Conservation, the Office of Energy Data and Analysis, and the Office of Research and Development. The Office of Energy Conservation

will promote consumer awareness of energy conservation, develop studies on measures to reduce energy requirements, coordinate all Federal, State, local and industry participation in energy-saving programs, and develop contingency plans for nation-wide power, fuel, and mineral resource emergencies. The Office of Energy Data and Analysis will develop energy information systems and analytic capabilities to assist Federal officials in short and long-term energy policy decisions. The Office of Energy Research and Development will set energy priorities, coordinate Departmental budgets and programs, and direct the underground electricity transmission research program. Two of these offices, the Office of Energy Conservation and the Office of Energy Data and Analysis, have been transferred from the Department of the Interior to the new Federal Energy Office.

If demand for energy could be reduced sufficiently, the projected oil and gas production from the proposed lease sale would be unnecessary. However, it is misleading to view the choices as either (1) producing 6-12 thousand barrels of oil and 0.9-1.5 billion cubic feet of gas per day from the Texas OCS #34 sale leases or (2) reducing demand for energy by this amount. Several considerations invalidate this reasoning: the widening gap between demand and supply of energy from all sources in the near future, the immediate shortage of natural gas and the need for oil to accomodate some of the unfulfilled demand for gas, and the limitations from the point of view of technology, cost, and time lag on substitution of other energy sources for oil and gas.

2. Conventional Oil and Gas Supplies

A. Onshore Oil and Gas Production

TECHNOLOGICAL PROCESSES 1/, 2/, 3/

The development and final utilization of oil and gas involves a wide range of operations, wherein the oil and gas must be found in a natural underground reservoir, lifted to the surface, transported to refineries, refined into more than a thousand products, and, finally, marketed and distributed.

Exploration

The first phase in petroleum production involves locating the hydrocarbon reservoir. Generally petroleum is found in porous sedimentary rocks where favorable geologic conditions have occurred to form traps. The two favorable geologic conditions necessary to form a trap are a layer of porous, permeable rock, usually sandstone or limestone, whose tiny pores may contain the hydrocarbons, and adjacent impervious layers of rock such that a barrier is formed to halt the movement of the hydrocarbons and, hence, enable their accumulation. Oil and gas, after they were formed, migrated through the pores in the rock until they reached an impermeable barrier. Here they accumulated and reached a

1/ Breeding, Burke and Burton, Income Taxation of the Mineral Industry, 1972, pp. 103-112.

2/ Meadows Paul, "Petroleum", U.S. Bureau of Mines, Mineral Facts and Problems, 1970, (Bulletin 650) pp. 147-182.

3/ Warner, Arthur J., "Natural Gas", U.S. Bureau of Mines, ibid, pp. 111-136.

steady state under relatively high pressure. Not all traps contain oil and/or gas, but those that do are called reservoirs. Three of the most common traps, the anticlinal, fault, and stratigraphic traps, are illustrated in the following diagram:

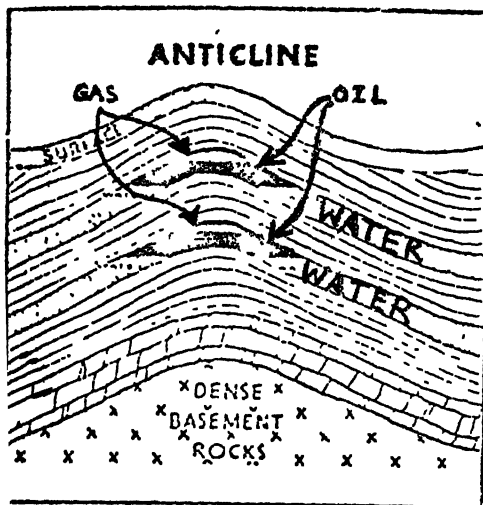


Fig. II-1

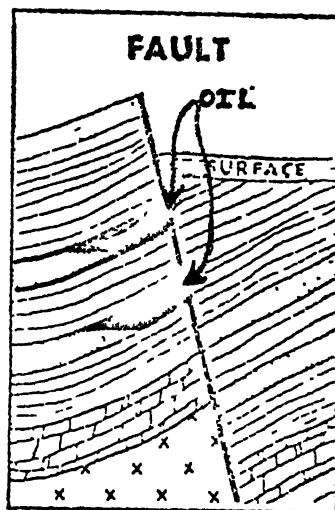


Fig. II-2

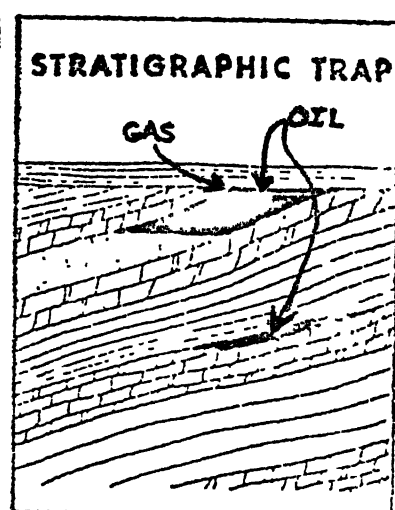


Fig. II-3

(From *Petroleum Discovery and Production*, pamphlet, American Petroleum Institute, New York, N.Y.)

The anticlinal reservoir is formed when a layer of porous rock, bounded above and below by impermeable layers of rock, is uplifted in such a way that the hydrocarbons are held in the crest of the porous layer. Hydrocarbons, being less dense than water, assume the higher position, and gas, if present as a separate phase, may form a "cap" by assuming the highest position in the trap.

In the fault trap reservoir, the porous layer abuts on an impermeable rock mass, placed there by faulting. The impervious layer prevents further lateral or upward migration of fluids.

In the stratigraphic trap, the porous layer abuts on an impermeable rock mass that is not the result of faulting, but the product of other geologic processes. In whatever manner the layers arrived at their configurations, when a porous stratum is surrounded by impervious strata and its pore spaces contain hydrocarbons and/or water, a reservoir is formed and the fluids are held in place in the trap.

These traps are initially located by a seismic survey. In seismic exploration an energy source generates a series of small amplitude seismic pulses that travel at thousands of feet per second through the earth and are reflected and refracted by the various subsurface strata. An array of sensitive geophones detects the returning seismic waves and records them on magnetic tape. These recordings are subject to highly sophisticated electronic data processing resulting in an end display of cross-sections and maps of the various subsurface formations and, hopefully, they will reveal and locate some of the above pictured traps. Formerly, seismic exploration revealed only these trap structures; they did not reveal the presence or absence of hydrocarbons, nor did they reveal traps not formed by the shape of rocks. Very recently, however, new techniques have been developed which more readily reveal traps and which provide some clues as to the presence or absence of hydrocarbons. Receiving devices that have greater

sensitivity can record echoes from the substrata with such precision that the strengths of these echoes can be measured. Stated simply, water-filled strata return a weaker echo and an echo of opposite polarity than strata filled with hydrocarbons. 1/, 2/ While these new techniques in seismic surveying may not be foolproof and may not indicate whether or not a hydrocarbon reservoir contains enough oil or gas to be commercial, they are an important improvement in exploration for hydrocarbons. The final step in the exploration phase is the drilling of a "wildcat" well which is the actual proof of whether or not the suspected structure actually exists, and, if so, whether or not it is a trap that contains oil and/or gas in commercial quantities.

Drilling

Most present day drilling is performed with a rotary drilling rig. The hole is dug by a drill bit which grinds the rock. The bit is located at the end of a string of drill pipe. At the surface, the drill string including the bit is rotated by a rotary table and a special square or hexagonal joint of pipe called a kelly joint. At the bottom of the hole, the action of the bit crushes the rock and advances the hole. To remove the cuttings, a circulating fluid called mud is pumped down into the hole through the kelly, drill pipe and bit. The mud that comes out of the bit picks up the cuttings

/ Taken from testimony of Carl H. Savit presented at OCS Public Hearing, Tallahassee, Florida, August 22, 1973.

/ Lindsey, J. P. and Craft, C. I., "How Hydrocarbon Reserves are Estimated from Seismic Data", World Oil, August 1, 1973, pg. 23.

and transports them to the surface as the mud continues flowing upward in the annular space between the drill pipe and the wellbore.

The mud serves another purpose equally as important as removing the cuttings from the hole. That is, the column of mud exerts a hydrostatic pressure on the formations that have been or are being penetrated. Whenever a fluid-bearing formation is encountered by drilling, the weight of the mud prevents the formation fluid from entering the wellbore. This is essential for preventing an uncontrolled rush of gas or oil into the wellbore, possibly flowing uncontrolled to the surface and causing a blow-out. Blowouts are extremely dangerous because they are difficult to control and the highly flammable nature of hydrocarbons poses a threat to all concerned. It might be noted, on the other hand, that since drilling mud keeps formation fluids out of the hole, it is possible to drill through a hydrocarbon-bearing formation without being able to detect it.

To confirm the existence or absence of hydrocarbons, various tests must be performed. The two most commonly used methods are logging and the drill-stem test. Logging consists of lowering an electrical device into the wellbore to measure various electrical properties and provide clues as to which formations contain hydrocarbons. The drill-stem test is a method by which the well is temporarily completed 1/ and is allowed

1/ See discussion of well completion in the next section.

to flow through the drill pipe. From the resultant flow, the fluids obtained confirm the existence of oil or gas. A drilling rig is pictured in Fig. II-4.

Well Completion

Once the existence of a commercial reserve of oil or gas has been confirmed by logging or by a drill-stem test or other method, the well must be completed. To complete the well, the drill string and bit are removed and a string of large diameter pipe (called casing) is lowered into the hole far enough to reach or pass through the hydrocarbon zone. The empty space between the casing and the wellbore is filled with cement to seal off the various formations which have been drilled. Adjacent to the hydrocarbon-producing zone, the casing and cement are perforated so that oil or gas can drain into the well. The placing of the casing having been completed, tubing is placed in the well. The tubing is simply a smaller diameter string of pipe that fits inside the casing and conveys the fluids to the surface. Finally, a wellhead consisting of control valves is installed on the surface. Fluids travel up the tubing, through the wellhead and into a gathering line which takes the gas and/or oil to be further treated. 1/

1/ Treatment of produced oil and gas is covered in the next section entitled, "Production".

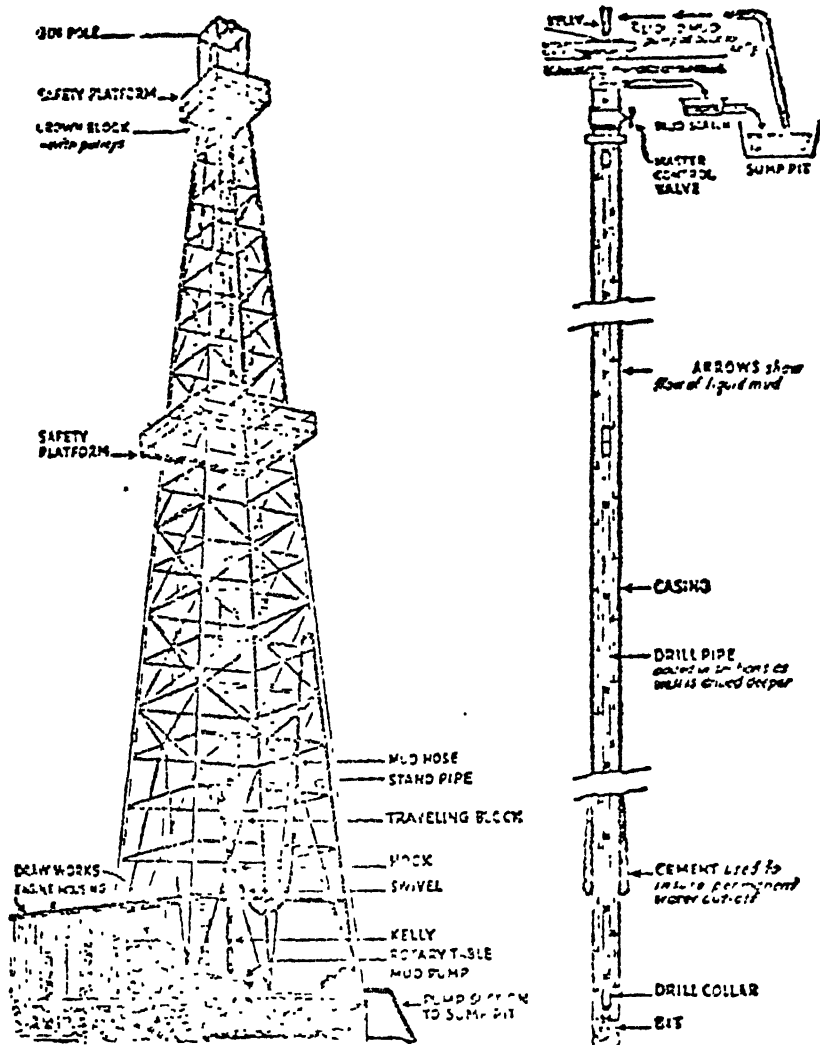


Fig. II-4 Rotary drilling rig.

Left: derrick—above ground.

Right: drilling operations—below ground.

Hydrocarbon reservoirs may be sizeable and it is an important part of developing a field to drill a sufficient number of wells as to develop the resource in the most profitable manner without waste. Additional wells are drilled and completed in the same manner as described above.

Production

Crude oil is brought to the surface from the reservoir by artificial means or by natural flow if there is sufficient reservoir energy in the form of pressure. The reservoir pressure and gas in solution determine the available driving forces. Artificial lift is accomplished by pumping or by injecting high pressure gas into the well to gas-lift the fluid. Gas produced from a gas well flows to the surface under its own pressure.

The fluid produced from gas wells is essentially only gas and may go directly from the wellheads via gathering lines to a gasoline plant or to a common carrier main pipeline.

The fluid produced from an oil well is comprised of both oil and gas and usually water so provisions must be made for separating the three components of the fluid before quantitative measurements can be taken. Normally the fluid flows from the well to an oil and gas separator. The gas is metered and sent to a pipeline, the water and oil are sent to another type of separator and the oil then proceeds to a stock tank while the water is disposed. The crude usually is gauged in the stock tank; oil production in the U. S. is measured in stock tank barrels. From the stock tank, oil is then transported via pipeline to a refinery tank farm.

Refining/Marketing

Finally, the crude oil enters the refinery where it is converted into the thousands of specialized products which modern refining techniques are capable of producing. The majority of the natural gas goes directly to both domestic and commercial fuel consumers via pipeline. The specialty products from the refinery are usually packaged at the site (drums, cans, bottles, cases) and moved to the final sales point by air, rail, or highway. Large volume products (gasoline, jet fuel and fuel oil) are delivered by pipeline to area tank farms and then to retail outlets or final consumers via tank truck.

New Technology in Exploration, Production, Transportation, Refining

The evolution of new technology has resulted in improved search techniques. Perhaps the most promising new development in exploration is the more sensitive receiving device that enables the surveyor to determine not only the presence of a trap structure, but also whether or not the structure contains hydrocarbons. This seismic breakthrough has been used in the OCS area from Florida to Texas in the Gulf of Mexico and has revealed many promising areas that may contain large amounts of oil and gas.

Improved technology in production methods has been particularly noteworthy. Water flooding has been developed into a process whereby an amount of oil can be recovered that is approximately equal to the volume of oil recovered by primary methods.

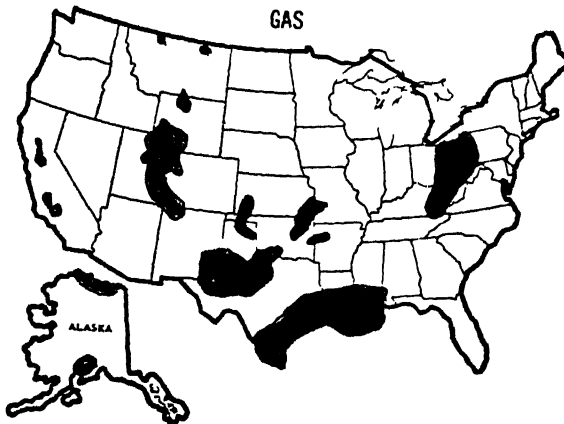
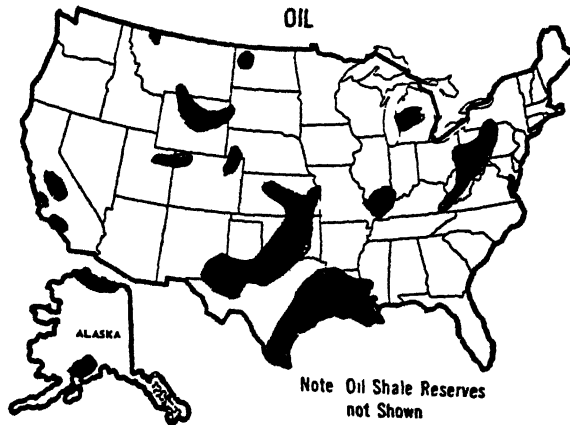
Fracturing is a method whereby the producing capability of a particular well can be increased. In hydraulic fracturing water under pressure is pumped into a well. The water enters the formation and actually enlarges the cracks in the reservoir rock. A propping agent such as little glass beads or sand is mixed in with the fracturing fluid and is also pumped into the well. The propping agent is forced into the newly opened fractures along with the fluid and remains in place after the well is drained. As the name implies, propping agents keep open the fractures after the fracturing fluid is removed. With a widening of the fractures, the oil can flow with greater facility toward the well and into the wellbore. Another similar method of opening fractures in reservoir rock is by acidizing. This involves pumping acid into the well to dissolve some of the rock and enlarge the fractures so the oil can flow more freely.

Concerning transportation of hydrocarbons, recent technological developments have resulted in decreasing cost levels. Of particular significance has been the installation of highly automated, large diameter, thin walled (high strength steel) pipeline systems as well as better protective coatings and insulation.

Technological advances in the refining phase of petroleum production have mainly come about through an increase in the use of computers. Complementing the increasing trend toward automation, recent advances in the technology of petroleum refining have resulted in increased production, reduced operation costs, and improved quality control.

RESOURCE BASE

Oil and gas reserves are located in many areas of the United States but, as indicated in the figures that follow, the largest reserves are found in the mid-continent and Gulf Coast regions. 1/



1/ Federal Power Commission, The 1970 National Power Survey, 1971, Part 1, pp. 4-6.

The Geological Survey has compiled the following table showing various categories of onshore reserves.

Table II-I U.S. ONSHORE OIL AND GAS RESERVES 1/

<u>Oil and Natural Gas Liquids</u>			
	Measured Reserves <u>2/</u>	Indicated and Inferred Reserves <u>3/</u>	Undiscovered Recoverable Reserves <u>4/</u>
Federal Lands	1.8 billion barrels	1.0-1.5 billion barrels	15-30 billion barrels
State Lands	38.9 billion barrels	21.0-37.0 billion barrels	120-240 billion barrels
<u>Natural Gas</u>			
Federal Lands	16.2 Trillion cubic feet	8.0-15.0 Trillion cubic feet	75-150 Trillion cubic feet
State Lands	202.1 Trillion cubic feet	89.0-190.0 Trillion cubic feet	530-1060 Trillion cubic feet

1/ Testimony of Dr. Vincent E. McKelvey, Director, U.S. Geological Survey, before the Special Subcommittee on Integrated Oil Operations, Senate Interior and Insular Affairs Committee, February 20, 1974.

2/ These figures are compiled from industry sources.

3/ These figures are derived by the Geological Survey from data submitted by industry.

4/ These figures are estimates calculated by the Geological Survey.

Proved reserves are a function of both economics and technology. Increases in prices of oil and gas increase proved reserves and ultimate production from given deposits because it becomes economical to develop previously uneconomical deposits and to employ secondary and tertiary recovery techniques. Recent price increases have expanded proved reserves and modified the above figures, shifting part of "recoverable resources" into the category of "proved reserves". However, until oil and gas prices stabilize, it is difficult to quantify this shift.

[REDACTED]

Alaskan Oil and Gas Reserves

The Prudhoe Bay field currently is estimated to contain 24 billion barrels of oil-in-place. At an estimated recovery rate of 40%, the current proved recoverable reserves of the field are 9.6 billion barrels of crude oil. 1/ These reserves alone make the Prudhoe Bay field the largest ever discovered on the North American continent. 2/ Nevertheless, the 9.6 billion barrel estimate may be a conservative indication of the crude oil potential of the field and the Arctic Slope province.

The current reserve estimate for the Prudhoe Bay field is for unextended pools and assumes primary recovery only. With further developmental drilling and application of secondary recovery techniques, it is likely that at least 20 billion barrels of crude oil will eventually be recovered from the Prudhoe Bay field. This would make it the fifth largest oil field ever discovered in the world. 3/

1/ American Gas Association, American Petroleum Institute, and Canadian Petroleum Institute, Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada and United States Productive Capacity as of December 31, 1970, May 1971, p. 27.

2/ Halbouty, Michael T., et al., "World's Giant Oil and Gas Fields, Geologic Factors Affecting Their Formation and Basin Classification", American Association of Petroleum Geologists, November 1970, Geology of Giant Petroleum Fields, Memoir 14.

3/ Halbouty, Michael, T., et al, ibid.

The Prudhoe Bay field has large reserves of natural gas dissolved in or associated with its crude oil reserves. Recoverable gas reserves in the field were estimated to be 26 trillion cubic feet as of the end of 1970. 1/ An average of 750 cubic feet of dissolved gas per barrel 2/ for the proved oil reserves of 9.6 billion barrels would indicate reserves of approximately 7 trillion cubic feet of dissolved gas and 19 trillion cubic feet of associated gas. These reserves, which, like the crude oil reserves of the Prudhoe Bay field, are subject to extension and revision, constituted 8.9 percent of recoverable U.S. natural gas reserves at the end of 1970. 3/ They also make the Prudhoe Bay field the thirteenth largest gas field ever discovered in the world. 4/

The estimated reserves of the Prudhoe Bay field do not exhaust the oil and gas potential of the Arctic Slope province in Alaska. The Prudhoe Bay field is located in the Colville Basin. Geologically, this basin is classified as an intermediate crustal type (i.e., its underlying

1/ American Gas Association, et al., op. cit., p. 170.

2/ Suggested by the data given in U.S. Bureau of Natural Gas, Federal Power Commission, National Gas Supply and Demand: 1971-1990, pp. 98-99.

3/ American Gas Association, et al., op. cit., p. 174.

4/ U.S. Bureau of Natural Gas, Federal Power Commission, op. cit., p. 74.

crust is intermediate to that beneath continents and that beneath oceans the basin itself being extracontinental (located on the margin of a continent) and sloping downward into a small ocean basin. Extracontinental, downward warping basins are among the richest sources of oil and gas in the world. Examples of such basins include the Arabian platform and Iranian basin (Persian Gulf), the East Texas basin, the Tampico embayment (Mexico). Over half of the 119 known oil fields with at least one billion barrels of recoverable reserves are found in the 10 known basins of this type. 1/

The ultimate potential of the onshore area in the Arctic Slope province is uncertain. The platform along the Arctic Coast gives considerable geologic indications of being very favorable for both oil and gas. 2/ Comparison with the history of similar basins indicates a high probability of further discoveries of varying size. Professional estimates of ultimate recovery for the province range from 30 to 50 billion barrels. 3/, 4/ The Prudhoe Bay field alone is likely to supply 10

1/ Halbouty, Michel T., et. al., *ibid.*

2/ Gryce, George, "Summary of Potential Petroleum Resources of Region 1 (Alaska and Hawaii) Alaska", and Brosge, W. P. and TAILLEUR, I. L.; "The Northern Alaska Petroleum Province", American Association of Petroleum Geologists, Future Petroleum Provinces of the United States--Their Geology and Potential, Vol. 1, Memoir 15, 1971.

3/ Cram, Ira H., "Future Petroleum Provinces of the United States--Their Geology and Potential: Summary", American Association of Petroleum Geologists, *ibid*, p. 24.

4/ Schurr, Sam H. and Homan, Paul T., Middle Eastern Oil and the Western World: Prospects and Problems, New York, 1971, pp. 86-87. Personal communications with Richard Meyer, U.S. Office of Oil and Gas; George Gryce, U.S. Geological Survey, both of U.S. Dept. Interior.

billion barrels of crude oil. Considerably higher estimates than these have been made, 1/ but the geologic evidence for them is lacking.

Similarly, the natural gas prospects of the North Slope are not limited to the Prudhoe Bay field. Several gas fields were discovered in the 1940's and 1950's on NPR-4 (Naval Petroleum Reserve No. 4), the largest of which was the Gubik field with 300 billion cubic feet of reserves. Geologic investigations of other parts of the North Slope have indicated a favorable potential for future gas discoveries within them as well. 2/

1/ Governor Egan of Alaska was quoted in The Oil Daily July 7, 1971, p. 3, with an estimate of 150 to 300 billion barrels.

2/ See "The Northern Alaska Petroleum Province."

ECONOMIC CONSIDERATIONS

Prices and Costs 1/, 2/

An overview of the major factors affecting oil and gas cost-price relationships is amply provided in the National Petroleum Council report entitled "Factors Affecting U.S. Exploration, Development, and Production, 1946-1965." Highlights of that presentation include the following: (1) Federal and State policies with respect to leasing of Federal and State lands, taxes and production, and unitization of properties; (2) the changing behavior of price relative to cost factors such as wage rates and payments for oil field materials and machinery; (3) the decrease in many areas of geological opportunities to make profitable discoveries, especially the older shallow areas, and the shift to the more expensive operating areas of Alaska and deep inland areas; (4) the changing structure of the industry which is evident in the decline of small companies and individuals and increasing concentration of operations among the large integrated companies; and (5) a decreasing proportion of total industry's revenue from oil and gas production spent on domestic exploration and drilling.

1/ Meadows, Paul, op. cit., pp. 162-163.

2/ Warner, Arthur J., op. cit., p. 123-124.

Economic factors governing the level of crude oil prices at the wellhead are established for areas and fields on the basis of oil and/or gas quality and type, market supply-demand relationships, the competitive relationship of oil as delivered to refineries compared with oil from other fields, and other factors. The 1972 average wellhead value of crude oil in the U.S. was \$3.39 per barrel and the value of natural gas averaged 18.6¢ per thousand cubic feet. The gross value of revenues from production of petroleum totaled over \$11 billion; the gross value of gas totaled about \$4 billion. The 1973 average wellhead value of crude oil in the U.S. was \$3.89 per barrel and the value of natural gas averaged 21.3¢ per thousand cubic feet.

Because of the general industry attitude concerning the confidentiality of cost data coupled with the physical properties of oil and gas, the environment in which they are found, and the manner in which they are produced, projections of the cost for finding and producing oil and gas are subject to considerable uncertainty. Further complicating the determination of oil and gas costs is the association of oil and gas in the same reservoir and the consequent producing operations to handle both oil and gas simultaneously. In 1973, it was estimated that the cost incurred in drilling and equipping wells and other yearly costs of finding, developing and producing oil and gas in the U.S. was about \$5.2 billion. Of this, about \$1.0 billion was for lease bonuses,

\$2.9 billion for drilling and the remainder for production and equipping wells. In 1972, 29,510 wells were drilled which found 1.5 billion barrels of oil and 9.6 trillion cubic feet of gas. 1/ In 1973, 32,051 wells were drilled.

Industry Structure 2/, 3/

In the United States all phases of the development and utilization of petroleum and natural gas are performed by private companies, both large and small. The primary operations performed by these corporations include: 1) the search for and production of petroleum, 2) the transportation of petroleum from producing fields to refineries and distributors, 3) the refining of crude oil, and 4) the distribution of petroleum products to consumers.

1/ American Gas Association, American Petroleum Institute, and Canadian Petroleum Institute, Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada and United States Productive Capacity as of December 31, 1972, May 1977, pp. 74-110.

2/ Warner, Arthur J., op. cit., pp. 113-114.

3/ Meadows, Paul, op. cit., pp. 149-150.

Firms in the petroleum industry exhibit varying degrees of vertical integration as they perform one to all of the mentioned phases. Often subsidiary companies are formed to undertake supporting functions.

Major companies operate throughout the United States but predominate in areas requiring large investments for drilling and producing operations. Such areas include west Texas and Alaska. Petroleum located in mature producing areas is frequently produced by small independents and individuals. Recently many major and large independents have expanded their operations into other energy resource fields as well as petrochemical manufactures and other business areas.

The petrochemical industry is the nation's third largest industry, following agriculture and public utilities. The natural gas industry is the nation's sixth largest industry. Because natural gas occurs in association with petroleum, these commodities are often produced jointly.

Petroleum refineries are situated near producing areas, water transportation facilities, or large market areas. As of 1969, 20 companies controlled 80% of the 264 refineries in the U.S. In the natural gas industry 90% of interstate sales were made by 10% of the producers.

Transportation 1/, 2/

Pipelines and water carriers, including tankers and barges, are the primary modes of transport for three-fourths of the movement of crude oil and all but a negligible fraction of the distribution of natural gas. Major extensions of trunk pipelines played a large part in the expansion of natural gas production in the 1960's. Successes in pipeline technology, including the development of high-quality pipeline steel, welding processes, trenching machines, and efficient compressors, have played a significant role in spurring the growth of pipeline systems. Surface tank trucks are used to transport crude oil over short distances, with railroad tank cars reserved for the transport of higher value specialty products. Trucks in recent years have occupied a larger percentage of the transportation mix for refined products.

The domestic cost of transporting crude oil to the refinery may amount to as much as 50 to 60 percent of the delivered cost of oil. Cost for various types of petroleum transportation, including both short and long hauls, are compared as follows:

1/ Meadows, Paul, op. cit., pp. 166-168.

2/ Warner, Arthur J., op. cit., pp. 125-126.

Type of Transportation	Mills Per Ton-mile
Tanker	1.0-2.0
Barge	1.5-6.0
Pipeline	1.7-6.0
Tank Car	20-70
Tank Truck	30-50

From the above tabulation, it is evident that transportation costs bear an inverse relationship to the size of the mode of transport. Conversely, lower costs reflect longer hauls and the use of large-capacity carriers. Economies in the transportation of petroleum products have been achieved through increases in the scale of operations, greater use of automation, and better design and quality of materials.

Transportation of Alaskan Oil

Under the Trans-Alaska Pipeline proposal, all of the North Slope oil to be transported by that line would be delivered to and consumed on the West Coast (PAD V) within the first few years after full operation. Deliveries of oil from other fields and by other transportation facilities are too remote and too conjectural for meaningful consideration in current planning.

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proposals for gas pipelines up the Mackenzie River Valley to the potential markets. However, many major uncertainties remain; for example, at this time industry experts differ in their opinions about how soon the gas caps in the Prudhoe Bay field can be tapped. Assuming 750 cubic feet of dissolved gas per barrel of oil would be produced, 1.5 billion cubic feet of gas per day would be produced when oil production has met the full planned pipeline capacity and has come from the gas caps. The issue may not be fully resolved until several years after oil production begins, at which time empirical data on the effects of production of associated gas on the production of oil will be available. It is likely that a gas pipeline to the Midwest and lower Canada will ultimately transport gas from both the North Slope and the Mackenzie Delta region.

ENVIRONMENTAL IMPACT OF INCREASED DRILLING, PRODUCTION AND TRANSPORTATION

Impact on Air Quality

The impact of additional petroleum drilling and production on air quality stems principally from the emission of particulates into the atmosphere as described in the following discussion; however, some disturbances result from noise and vibrations. As long as operations continue, the above-mentioned impacts will continue to occur.

Particulates are introduced into the air during construction and use of access roads and drilling pads. Often times, public use of the access ways for off-road vehicle recreation greatly aggravates the initial surface disturbance. Air quality in immediate areas of development will undergo deterioration because of removal of ground cover, vehicle traffic and occasional equipment failure or blowouts. The removal of vegetation cover raises maximum surface temperatures and permits increased local wind velocities and evaporation rates. The burning of waste petroleum and chemical products, especially those containing sulfur, could result in an increase of particulates, gaseous pollutants, and objectionable odors. Vapor venting from storage tanks should also be considered as an air pollutant.

Noise and vibrations from stationary engines used in drilling operations, pumping units and compressor stations can cause disturbances in the natural environment and these disturbances will continue to occur throughout the life of petroleum-based operations. Noise and vibration could possibly alter the feeding and nesting habits of birds and animals, but it is highly unlikely that reduction in air quality from increased petroleum production could significantly alter conditions affecting the growth of plants and animals.

Impact on Land Quality

The modification of land form necessary for petroleum production results in varying degrees of environmental impacts on the physical and chemical land characteristics, the biological conditions, the cultural factors and the ecological relationships.

Depending on the terrain and local ground conditions, access to the drill site is normally from existing road networks, extension of these roads and expansion of trails. For initial exploratory work in a given area, only minimum alterations are made in roadway systems, but, after the decision is made to continue with development drilling, an improved road system is required for the transportation of the heavy drilling and production equipment.

The drill site must be cleared of vegetation and obstacles, graded and leveled. If metal storage tanks are unavailable, then reserve and waste pits must be dug to contain drilling muds and capture formation fluids to prevent pollution of the adjacent land and/or water. When production has been established, newly constructed roads are improved. The impacts resulting from these operations include removal of top soil and surface vegetation to establish corridors and alteration of drainage patterns and watershed cover.

In the construction of roadways, surface vegetation is removed and drainage patterns are modified. As a result, erosion can occur resulting in changes in landform. Trees, shrubs, grass, and crops may also be subjected to indirect effects by modifications of drainage patterns. Soil erosion and siltation can have both direct and indirect impact upon the normal behavior and activity patterns of wildlife. Small animals and birds may not be significantly affected, although their number in the immediate vicinity of the operations might decrease in proportion to disturbances and lost habitats. Disturbance of the habitat may well continue beyond the life of the producing and transporting operations.

Land use and recreation activities may also be disrupted during drilling, producing and transportation operations. Aesthetic and human interest factors are affected for a time-frame beyond the termination of operations. Scenic views and vistas, wilderness

qualities, and physical features in some localities could undergo alterations that could be considered permanent transformations. Population density, employment, and cultural life-styles would change from drilling, production, and transportation levels. The change would be of long-term impact and directly affect access, utility networks, waste disposal and creation of additional corridors.

While the construction of pipeline facilities has the potential for causing unfavorable environmental effects, the employment of good construction techniques can minimize or even eliminate most of these effects. Farming or grazing lands can usually be restored to their original condition after no more than one growing season by the replacement of top soil and the replanting of grass or crops. The aesthetics of wilderness areas can be preserved by using existing rights-of-way or minimizing the width of new rights-of-way by replacing grass and shrubs on the rights-of-way and by using such techniques as feathering and germinating or deflecting of entranceways. Any displacement of wild animals will occur primarily during the construction. Banks can and should be stabilized to avoid erosion during construction. Access and service roads should be maintained with proper cover, water bars and appropriate slope to avoid soil erosion. Compressor

stations and other above-ground facilities can be located in unobtrusive sites and planted with appropriate trees and shrubs to enhance their appearance; location, planting and exhaust design can be used to abate excessive noise associated with operation of the compressor stations. Treatment plants can be located and equipped with devices to minimize any adverse effects upon air quality and suitable means, e.g., evaporation ponds or disposal wells, can be found for preserving the water quality of the surrounding area.

Perhaps the greatest adverse environmental impact from oil and gas operations results from oil, chemicals, brine, or waste material pollution. This pollution can result from spills, leaks, blowouts, human errors, or equipment failure. Although care is exercised to prevent land pollution, there are no fail-safe methods to completely protect the environment.

Land pollution, primarily from salt water and accidental oil spills, can result in soil sterilization that could be of a long-term nature and affect not only the topsoil but underground water quality.

Native vegetation and crops can be adversely affected for short or long-term duration depending upon the volume and toxicity of the pollutant, resistance of the flora, and in turn affect the habitat of birds and animals. Depending upon the degree of pollution, land uses such as agriculture, grazing, forestry, and

wilderness can be altered for varying time-frames. In some cases large pollutant concentrations could be sufficient to kill vegetation, trees or crops and disrupt wilderness areas for a long time. Recreation in areas subjected to large pollutant concentrations can also be altered for long time-frames.

Depending upon local conditions, aesthetics such as scenic views and vistas, wilderness qualities, unique ecosystems, or historical sites and objects may be altered. The degree of alterations would be dependent upon the degree of pollutant introduction and local conditions. Disruption of ecological relationships such as food chains and salinization of soil and water resources could result from pollutant contamination. The degree of contamination has a bearing upon the duration of the environmental impact.

In exploring and pipelining, any spills that occur normally would be small. Major spills could occur in drilling; and production and in the movement of petroleum liquids by marine transportation.

The Federal Water Quality Administration (EPA) estimates that 10,000 oil spills occur yearly of which 2,600 are ground spills. ^{1/} Most ground spills cause little ground pollution. According to the 1970 report of the Office of Pipeline Safety (Department of Transportation) on spill incidents, spills averaged approximately

^{1/} National Petroleum Council, Environmental Conservation, The Oil and Gas Industries, Vol. II, 1972, p. 146.

1,780 barrels of crude oil. Principal cause of over 50 percent of accidents was corrosion. Many onshore pipelines are old, dating back to 1920's before techniques for protection against corrosion became widely used. Continued accidents can be expected from these lines. With the development and expanded use of cathodic protection of pipelines, fewer accidents in new lines are expected, but accidents from old lines will continue to be of concern.

Impact on Water Quality

The construction of roads for access into prospective petroleum producing areas could affect water quality by disturbing drainage patterns and causing erosion. The dredging of canals could result in increased turbidity and resuspension of bottom sediments as well as salt water intrusion.

Turbidity is considered to be of short-term duration but may affect local flora and fauna. Siltation of water reservoirs and estuaries has long-range environmental impacts in that the shape and size of the water basin is altered. This can have an adverse impact on flora, recreation activities, aesthetic qualities and, perhaps, disturb ecological food chain relationships.

One of the major environmental risks of petroleum production operations is the entry of foreign substances such as oil, chemicals,

brine, and waste materials into the water cycle. Spills or leaks releasing these substances result from human error, corrosion of pipelines and vessels, ruptures or mechanical failures, burning pits, open ditches and blowouts.

Large amounts of salt water may accompany oil production as oil fields age. Such water can create pollution problems from producing wells on land or freshwater-covered areas. According to a study of the Interstate Oil Compact Commission (IOCC), up to 25 million barrels of salt water are produced daily from the nation's oil wells. Proper disposal of produced brines has been and continues to be of major concern to producing operators and regulatory agencies. Subsurface disposal is strictly regulated by some state conservation agencies and disposal of salt water is not permitted in freshwater streams. 1/

The introduction of oil or brine into the water cycle can adversely affect vegetation and aquatic plants, birds, land animals, and fish. Sheltered lagoons and estuaries impose natural dispersal restrictions on oil spills causing the oil to remain trapped or concentrated in such areas for long periods. Major reductions in water quality that significantly disrupt the food chains in bays, lagoons, and estuaries could have long-term environmental effects.

1/ National Petroleum Council, op. cit., p. 147.

SPECIAL CONSIDERATIONS - Nuclear Stimulation

Nuclear stimulation, an experimental method of fracturing low permeability gas reservoirs otherwise incapable of sustaining commercial production, has potential to add materially to U.S. recoverable gas reserves. The Atomic Energy Commission is conducting research and development of nuclear explosives and techniques for utilizing the effects of multiple nuclear explosives to recover natural gas locked in tight geological formations. Such gas cannot now be economically produced by conventional methods. Most reserves which are amenable to nuclear stimulation lie in thick, deep reservoirs of very low natural permeability located in the Rocky Mountain area.

Project Gasbuggy, a cooperative effort of the AEC, the Department of Interior and El Paso Natural Gas Company, involved detonation of a 29 kiloton nuclear explosive in the Pictured Cliffs formation, a gas-bearing formation near Farmington, New Mexico. The explosive, set off at a depth of approximately 4,200 feet on December 10, 1967, created an underground chimney containing about 2.3 million cubic feet of crushed rock. There was no unplanned release of radioactivity to the environment. By November 1969, nearly 300 million cubic feet of gas was extracted from the chimney through intermittent production testing of the well. A similar program, Project Rulison took place near Grand Junction, Colorado, in December 1969. It involved detonation of a 40 kiloton explosive at 8,430 feet.

Projects Gasbuggy and Rulison were basic experiments each involving the detonation of a single nuclear explosive but in different gas formations and at different depths. Both of these projects clearly demonstrated that recovery of natural gas by nuclear explosive stimulation is technically feasible and economically promising. The current development phase involves techniques for using multiple explosives in a single wellbore. Gas formations amenable to nuclear explosion stimulation are thicker than can be effectively and feasibly stimulated by a single explosion. The Rio Blanco Project, part of this phase, involved simultaneous detonation of three 30-kiloton nuclear devices more than a mile underground on May 17, 1973. The stimulated well near Weeker, Colorado, is expected to produce 17.5 billion cubic feet of natural gas from sandstone formations. The gas should fill the chimney created by the explosions from where it can be piped to the surface.

The Atomic Energy Commission has reported on the possible scope of nuclear stimulation and has provided an economic assessment of the technical programs needed to achieve commercially viable application of nuclear stimulation of natural gas wells. Current emphasis in AEC's Plowshare program is to develop technology. A research and development period of approximately 5 years is required; it includes the design and testing of explosives and execution and evaluation of pilot tests in each basin. The Rio Blanco Gas Stimulation Project impact statement discusses a three-phase demonstration program for the Rio Blanco Unit which is being considered by the industrial

sponsor but for which there is, as yet, no Government commitment. Assuming success during experimental testing, commercial development could begin by the late 1970's. A scenario developed by the Lawrence Radiation Laboratory (LRL) ^{1/} assumes technical capability and public acceptance of drilling, necessary field construction, and explosive firing of 80 wells (290 explosives) per year by 1980. This could result in the production of about 600 Bcf of natural gas per year by that time. Favorable conditions might allow a development program of 100 wells (370 explosives) per year beginning in 1981. Such a schedule could yield 1.50 Tcf per year (4.35 billion cf/day) by 1985. This corresponds to an energy production of 4.35 trillion Btus/day.

Environmental Impact

Environmental effects of nuclear stimulation to increase natural gas production from tight reservoirs are related to radioactivity and seismic disturbance, both of which concern the surface or subsurface, leaving atmospheric contamination or disturbance unlikely. The depth of the gas formations of interest throughout the Rocky Mountain area is such that the probability of releasing any appreciable amounts of radiation to the atmosphere at detonation time is considered negligible. Most radioactivity produced by the explosives will remain underground, trapped in the resolidified rock near the bottom of the

^{1/} Rubin, B., Schwartz, L., and Montan, D., An Analysis of Gas Stimulation Using Nuclear Explosives, Rept. UCRL-51226, May 15, 1972.

chimney or attached to the rock surfaces in the chimney. Project design would take into account mobile waters and assure that chimneys remain isolated from them. The formations of interest for nuclear-explosive stimulations are generally at depths of 5,000 to 10,000 feet or deeper, have low permeability, and would not be expected to contain mobile water. Significant vertical communication with shallow water-bearing formations through existing or created faults or fractures must be avoided. Water produced with the gas from nuclear-explosive stimulated wells will contain very low levels of tritium. Control methods of disposal of this contaminant are being developed.

The chemical composition of the gas itself in each stimulated well is assumed to be similar to that measured in the first experiments. The initially large carbon dioxide concentration in the chimney either would be reduced by dilution with pipeline gas or would be removed by standard gas field practices. After production of a few chimney volumes, the carbon dioxide would be depleted and the gas composition would be essentially the same as that from conventional wells. Gas production from the wells could be delayed until short-lived radionuclides decay. Technical information from subsequent experiments will aid in defining the time for initiation of production.

The remaining gaseous isotopes--tritium and krypton-85--are produced with the first few chimney volumes of gas calculated to provide less than one milliroentgen per year of exposure to the general population if the gas were used as a part of the total gas supply to a large city. No insurmountable problem is anticipated in meeting future regulations or standards developed for sale of the gas.

The potential environmental impacts resulting from nuclear stimulation of a single well or in a small geographic areas have been evaluated in the environmental statements prepared for the Rio Blanco ^{1/} and the proposed Wagon Wheel ^{2/} projects. Extrapolation of the impact to a full commercial development relates primarily to the frequency and size of explosives and to changes in local environment as the areas of development expand.

The scenario developed by the AEC's Lawrence Radiation Laboratory describes drilling and firing of 100 wells per year (for possibly 50 to 60 years). On the average this would involve approximately 370 explosive devices per year, usually 3 or 4 explosives in each well. The AEC estimates that four detonation days per year should suffice for the 30 to 40 wells to be completed for each field area.

1/ U.S. Atomic Energy Commission, Rio Blanco Gas Stimulation Project, Rio Blanco, Colorado, Environmental Statement, April 1972 (Wash-1519).

2/ U.S. Atomic Energy Commission, Wagon Wheel Gas Stimulation Project, Environmental Statement, April 1972 (Wash-1324)

The size of the explosive required to stimulate the very thick geologic formations and the actual seismic effect of such devices are still being evaluated.

In extrapolating the projected or observed impact of test projects, consideration must be given to the total environment of the basin. The site for the Bio Blanco experiment, for example, is relatively isolated. There are thought to be no surface or subsurface structures or operations in the zone of substantial damage. The fact that this will not invariably be true is an important consideration when planning commercial development.

By its nature, nuclear stimulation has a dramatically disruptive effect on the nearby natural-gas host rock. The fracture zone should extend 300 to 400 feet from the center of the explosion. Also the compression wave moving out from the explosion can cause spall near a free surface (ground level) or other faulting or fracturing in areas where there is a large natural directional stress concentration. This would lead to concern if other valuable mineral resources exist in the area. However, the areas being considered for nuclear stimulation are relatively seismically inactive and would not appear to have large natural stresses required for such structural failures.

The development of nuclear stimulation of natural gas reservoirs may be accompanied by some possible damage of existing structures due to

ground motion. Damages would have to be prevented (as by bracing) or repaired or compensation rendered to owners. Ground motion is predictable and utmost care would be used to minimize this effect.

It has been suggested that residual stress from a number of detonations might accumulate and present an earthquake stimulation hazard not present in a single detonation. The best evidence available on this point is from experience with the Nevada Test Site where data from seismic wave generation and from stimulated fault motion indicate that the cumulative effect of many explosions is to reduce ambient stress levels rather than to increase them. A recent series of high-precision geodolite measurements indicates, also, that the residual strain field around a single explosion site tends to relax with time. In any case, observations of the seismic effects of a series of detonations would permit continuing appraisal of this issue.

RELATIONSHIP OF ALTERNATIVE TO PROPOSED OCS SALE

To directly substitute for the proposed sale, onshore oil production would have to increase by 6 to 12 thousand barrels a day and onshore gas production by 0.9 to 1.5 billion cubic feet a day.

The mix of oil and gas that would provide the same Btu value as the expected Texas OCS # 34 production ranges from all oil, 166,000 to 279,000 barrels a day, to all gas, 0.93 to 1.56 billion cubic feet a day. Economic incentives such as a rise in prices would be required to stimulate exploration and development in order to increase onshore production. Although prices of oil and gas have increased rapidly in the last year, it will be some time for price increases to be reflected in significantly expanded supplies of oil and gas. It is difficult to predict when and at what level oil and gas prices will stabilize. Current low exploration and discovery rates and declines in reserve levels must be reversed before production can begin to increase.

Production from Alaska North Slope oil fields would increase U.S. oil and gas supplies although legal and environmental difficulties have delayed development of the North Slope.

Under the Trans-Alaska Pipeline, all of the North Slope oil would be delivered to and consumed on the West Coast (PAD V) within the first few years of pipeline operation. PAD Districts I -IV, which would receive almost all of the oil and gas from the

proposed sale, would receive very little oil from the North Slope within the first years of its development.

B. Deregulation of the Wellhead Price of Natural Gas

BACKGROUND

The sale of natural gas for resale in interstate commerce is currently under Federal Power Commission (FPC) jurisdiction. In 1954, the Supreme Court ruled that independent producers of natural gas, whose sale of gas goes into interstate commerce, were not exempted from regulations under the Natural Gas Act.

Although in the past few years, the FPC has modified its pricing policies to be more responsive to the gas supply situation, including the recent order extending the sales period from 60 to 180 days for temporary emergency gas sales without FPC approval, on April 10, 1973, the FPC Chairman urged Congressional action to amend the Natural Gas Act to decontrol the price of new gas supplies. The President, in his energy message to Congress April 18, 1973, proposed such action stating:

"For more than a decade the prices of natural gas supplied to pipelines under this extended regulation have been kept artificially low. As a result, demand has been artificially stimulated, but the exploration and development required to provide new supplies to satisfy this increasing demand have been allowed to wither. This form of government regulation has contributed heavily to the shortages we have experienced, and to the greater scarcity we now anticipate.

As a result of its low regulated price, more than 50 percent of our natural gas is consumed by industrial users and utilities, many of which might otherwise be using coal or oil. While homeowners are being forced to turn away from natural gas and toward more expensive fuels, unnecessarily large quantities of natural gas are being used by industry.

Furthermore, because prices within producing States are often higher than the interstate prices established by the Federal Power Commission, most newly discovered and newly produced natural gas does not enter interstate pipelines. Potential consumers in non-producing States thus suffer the worst shortages. While the Federal Power Commission has tried to alleviate these problems, the regulatory framework and attendant judicial constraints inhibit the ability of the Commission to respond adequately.

It is clear that the price paid to producers for natural gas in interstate trade must increase if there is to be the needed incentive for increasing supply and reducing inefficient usage. Some have suggested additional regulation to provide new incentives, but we have already seen the pitfalls in this approach. We must regulate less, not more. At the same time, we cannot remove the price of gas currently in production and generate windfall profits.

To resolve this issue, I am proposing that gas from new wells, gas newly-dedicated to interstate markets, and the continuing production of natural gas from expired contracts should no longer be subject to price regulation at the wellhead. Enactment of this legislation should stimulate new exploration and development. At the same time, because increased prices on new unregulated gas would be averaged in with the prices for gas that is still regulated, the consumer should be protected against precipitous cost increases.

To add further consumer protection against unjustified price increases, I propose that the Secretary of the Interior be given authority to impose a ceiling on the price of new natural gas when circumstances warrant. Before exercising this power, the Secretary would consider the cost of alternative domestic fuels, taking into account the superiority of natural gas from an environmental standpoint. He would also consider the importance of encouraging production and more efficient use of natural gas."

Concurrent with the President's Energy Message, the Department of the Interior submitted to Congress proposed legislation to amend the Natural Gas Act. Until such legislation is passed by Congress, however, the wellhead price of new gas will continue to be regulated by the Federal Power Commission.

RESOURCE BASE

The Potential Gas Committee has estimated the remaining undiscovered reserves of gas in the United States as 1,146 tcf as of December 31, 1972, and has divided these reserves by region and by degree of uncertainty. This amount is approximately 4.9 times the 1972 proven reserves of the lower forty-eight states, indicating that substantial additional reserves may be developed if economic incentives improve.

ECONOMIC CONSIDERATIONS

Deregulation of the price of new gas is a policy option that if implemented, should stimulate the economic incentive for the discovery of new supplies and reduce inefficient use of the fuel. In order to determine the effectiveness of such policy options on these objectives, it is necessary to estimate the extent of producers' and consumers' responses to increasing prices.

When prices go up, producers find greater opportunity for profit in developing resources which might otherwise seem too risky or uneconomical to develop. On the other hand, consumers are less willing to pay higher prices and may curtail some uses of the fuel, tending to bring supply and demand into balance. While supply and demand elasticities have been the subject of much research, very little is known of the quantitative relationships.

Demand Elasticity

Six econometric studies were reviewed by Professor Draper in Regulation of the Natural Gas Producing Industry on price demand elasticity: 1/

1. Vermetten and Plantinga (1953). This study deals principally with the cross elasticity of gas and other energy sources in eleven industries aggregated by states. The elasticities ranged from -0.33 to -4.99 based on evaluation of 1947 data. (A -0.3 demand elasticity can be interpreted that a 10% increase in price would cause a 3% reduction in quantity demanded).

1/ Brown, Keith C., Regulation of the Natural Gas Producing Industry, pp. 49-55.

2. Wein (1961). This study used multiple regression analysis to estimate twelve equations involving factors thought to determine exploration, and residential, commercial and industrial demand. Cross section analysis was used for the year 1961 with data aggregated by state. The results indicated that elasticity of industrial consumption was about three times as large as the elasticity of residential and commercial consumption with respect to price; indicating that industrial users of gas respond more rapidly to higher gas prices by demanding less or converting to another fuel, than residential and commercial users. Industrial demand was highly elastic, -2.5, with combined residential and commercial demand having an elasticity of -0.8. Professor Draper intimates that one of the more important problems with the study is the choice of independent variables used to determine demand and exploration.

3. Villanueva (1964). This study attempts to estimate the variables affecting gas demand of the major sectors of the consumer markets and to estimate the effects of gas rates on the distribution of the fuel between consumer groups. Multiple regression analyses were performed with independent variables including prices of natural gas and competitive fuels, income, temperature, housing starts and measures of consuming-industry activity for the period 1950-60. Estimated price elasticities of -1.83, -1.39 and -0.51 resulted for regional gas demand of residential-commercial consumers in three of the five regions analyzed. Price elasticities of regional demand by industrial consumers ranged from -1.34 to -1.64 for three of the five regions. One of the major criticisms of this study is that data was aggregated to such an extent that an insufficient number of observations of the variables resulted in difficult interpretation of the statistically significant variables.
4. Balestra (1967). This study attempted to develop a dynamic demand equation for natural gas in the residential and commercial sectors of the economy. A short-run demand function relating demand to

availability of gas, the stock of gas-using appliances, the real price of gas and the real per capita income using 1950-62 data resulted in elasticities ranging from -0.00002 to -7.75. The conclusions from the short-run analyses were that the total demand for fuels is fairly inelastic in the short-run; substitution of fuels must be small in the short-run given the consumer's stock of major appliances; and the upward trend in elasticity suggests that competition from alternative sources of energy may become stronger in future years. Draper summarizes the limitations of this study as "...difficult to interpret the results when so many analyses were performed, their results are not in agreement, and there is no clear theoretical basis for choosing among the different models."

5. Tummala (1968). Two models were developed in this study to explain the demand for natural gas in the residential, commercial and industrial sectors using annual time series data for the state of Michigan from 1946-1964. One model, the simultaneous equations model, estimated burner tip price elasticities of demand in the residential, commercial and industrial sectors as -0.44, -0.60 and -1.33, respectively. The other model, a distributed-lag

model, produced some results not in accord with economic theory. Major problems were with the level of aggregation of the Michigan data and with the ensuing equations having statistically insignificant coefficients.

6. Gujarati (1970). This study attempted to determine the ratio of electric space-heating customers to total residential customers using price of electricity, price of gas, personal income of the consumer, degree days, and number of housing units of various types. Multiple regression analyses were used for the period 1963-1967 for twenty-seven privately owned utilities. This study is not directly relevant since we are concerned here with the effect of deregulation on the demand for and supply of natural gas to all users, not just the residential customer.

It is apparent from the review of these studies that widespread differences exist in the extent of demand elasticity of natural gas. Each study has its problems and limitations, as pointed out by Draper, making reliance on any particular set of elasticities suspect.

Another problem exists in that demand elasticity is analyzed in terms of end users only. When considering deregulation of wellhead prices in terms of its effect on supply-demand imbalances, supply and demand elasticities at the wellhead are more essential issues. None of the six studies addresses these issues, although wellhead demand is derived from user demand.

In summary, little can be said with assurance except that demand elasticity is negative. If the wellhead price of gas is deregulated, however, and such price increases ten percent, any decrease in demand by pipeline companies in the short-run might be expected to be less than ten percent.

Supply Elasticity

Four recent studies have been made concerning price supply elasticity. Some of the same problems concerning level of aggregation of data, availability of relevant data, serial correlation problems and proper identification of the supply function using significant variables from the data base, are prevalent in these studies as well. Although questions have been raised concerning the accuracy of these studies also, the results have not been as divergent as those concerning demand elasticity.

1. Garrett (1970). 1/ This study, using 1955-69 data, attempts to measure the reserves that would become economically exploitable due to an increase in the wellhead price of gas, not the amount that would be discovered. However, a constant elasticity of supply estimate can be derived of 0.5, indicating that a ten percent increase in wellhead price would increase natural gas supply five percent.
2. Erickson - Spann (1971). 2/ An attempt was made, using 1946-59 data, to account for the problem of joint costs, on the difficulty of separating gas well costs from oil well costs. It was concluded that oil prices have no long range effect on gas supply and may, in the short-run have a negative cross elasticity effect; in other words, an increase in oil price may decrease gas supply for a short period of time, but is not expected to have an effect on gas supply in the long-run. The best estimate of gas supply elasticity was 0.5, with a 0.69 elasticity over the long-run.

1/ Garrett, Ralph, "The Effect of Prices on Future Natural Gas Supplies," mimeographed.

2/ Brown, K. C., Regulation of the Natural Gas Producing Industry, pp. 192-218.

3. Khazzoom (1971). 1/ This model, developed for the Federal Power Commission, does not estimate a constant elasticity of supply value, but an equation based on 1961-68 data, showing gas supply as a function of several variables, one of which is price. Thus, the supply elasticity estimate varies from year to year, but varies under an assumed continuation of regulation.
4. MacAvoy (1971). 2/ Preregulation data in the period 1954-60 was used to empirically estimate a market clearing model, where supply, demand and wellhead prices were hypothetically at a state of equilibrium. The model is then applied to 1961-67 data and the differences between actual reserve additions and wellhead prices, and the market clearing values are compared. These differences are assumed to be the result of lower supply at lower regulated prices. A supply elasticity value of 0.45 was obtained for the long-run.

1/ The Bell Journal of Economics and Management Science, Vol. 2, No. 1, pp. 51-93.

2/ Brown, K. C., Regulation of the Natural Gas Producing Industry, pp. 169-191.

SUPPLY ELASTICITY ESTIMATES

<u>AUTHOR AND DATE</u>	<u>DATA</u>	<u>SUPPLY ELASTICITIES</u>
Garrett (1970)	1955-69	0.5
Erickson-Spann (1971)	1946-59	0.69 0.5 (best judgment)
Khazzoom (1971)	1961-68	No constant estimate
MacAvoy (1971)	1954-60	0.45

Thus, it appears that a 0.5 supply elasticity estimate might be a reasonable consensus of opinion of supply response to price. If the new average wellhead price is 27¢ per Mcf with reserve additions at 9.4 tcf, an increase in price to 40¢ might raise available reserve additions 2.3 tcf to 11.7 tcf. This price amount must be modified by an estimate of demand elasticity. Unfortunately, it is difficult to obtain a consensus on demand elasticity, since demand is established in reference to consumer as opposed to wellhead prices and since there is much variation in the available at 40¢ per Mcf, demand elasticities may have some effect on this price.

Two reports were issued recently one by the American Petroleum Institute estimating the impact of alternative deregulation proposals on natural gas prices and the other released by Representative Les Aspin and written by Dr. David S. Schwartz, Assistant Chief of the FPC Office of Economics. The API report estimates were based on analysis of gas sales contracts in effect on

January 1, 1973, varying assumptions as to market price levels in the event of deregulations, and projections of "new" and "old" gas delivery volumes to 1980.

Delivery volumes and prices of "old" gas were projected to 1980 from volumes and prices payable under existing contracts for 2 Bcf or more annually. It was assumed that prices would rise to the estimated market level upon expiration of the contract and whenever contractual provisions would permit. The study estimates that as of January 1, 1974, 62% of the sales volumes under existing contracts would not be subject to escalation to the current market price. This percentage would drop to 48% by January 1, 1980.

With respect to "new" gas sales, it was assumed that new supplies would be committed at the market price and that annual reserve additions would increase from 10 tcf to 19 tcf by 1975 and 27 tcf by 1980. The delivery volumes derived for "old" and "new" gas resulted in fairly stable production through 1976, increasing thereafter by approximately 2% annually.

The report noted that a positive relationship between supply and price was widely recognized, but that no technique as yet has been developed for reliably estimating the price elasticity of supply.

Projections of the impacts of deregulation at various market prices are summarized below:

Estimated Average Field Prices, All Sales

	<u>Deregulation of All Sales</u> -----	<u>Deregulation of New Sales and Expiring Contracts</u> (cents per Mcf)	<u>Deregulation of New Sales Only</u> -----
Assuming 55¢ Market Price			
1/1/74	26.80	22.96	22.08
1/1/77	35.84	32.17	30.11
1/1/80	45.66	43.43	39.52
Assuming 65¢ Market Price			
1/1/74	28.12	23.44	22.27
1/1/77	39.41	34.94	32.23
1/1/80	51.45	48.84	43.80
Assuming 75¢ Market Price			
1/1/74	29.45	23.92	22.46
1/1/77	42.97	37.71	34.36
1/1/80	57.25	54.25	48.07

The above estimates compare with the average field price of 20.48¢ for all interstate gas deliveries as of 1/1/73.

The report has aroused considerable controversy, criticisms have been made that the report is misleading and deceptive in that market price may rise considerably higher than the 75¢ maximum assumed level in the report with greater costs to the consumer.

The report by Dr. Schwartz, Assistant Chief of the FPC's Office of Economics estimated that deregulation of wellhead gas prices could cost consumers up to \$18 billion annually. The report assumes prompt renegotiation of all contract prices up to \$1/Mcf.

Dr. Schwartz determined that repricing of 1972 production volumes (22.9 tcf) assuming alternative prices under deregulation of 80¢, 90¢, and \$1 per Mcf, would result in added costs to consumers of \$13.5 billion, \$15.75 billion, \$18 billion respectively.

Dr. Schwartz also stated that these figures represent the upper limit in cost to consumers. Representative Aspin reiterated a prior charge that the API sponsored study shows only a gradual impact of deregulation on consumer price. 1/

ENVIRONMENTAL IMPACT

An analysis of the environmental impact of the proposed deregulation of the wellhead price of gas has been prepared by the Department of the Interior in its draft environmental impact statement. As stated

1/ Foster Associates Report, Nov. 29, 1973, No. 924, pg. 20.

in the statement, this alternative would not result directly in any specific action. It would, however, trigger market forces which would result in increased activities impacting on the environment. These activities would center on increased domestic production both onshore and offshore, of natural gas and associated oil. More detailed discussions of the impact of these activities are contained in both the draft statement on the proposed deregulation and elsewhere in this statement.

RELATIONSHIP OF ALTERNATIVE TO PROPOSED SALE

Under the Natural Gas Act, the Federal Power Commission has the authority to regulate the wellhead price of natural gas which goes into interstate commerce. It has been argued that the prices established by the FPC have been too low and have, therefore, increased demand, but have discouraged exploration and development. Studies of the responsiveness of the supply and demand of natural gas to price changes have been done; the results are, however, not conclusive. It is difficult to accurately predict the impact of deregulation. The amount of production which could be stimulated by this alternative could probably be greater than the production anticipated from the proposed Texas sale, but a more detailed prediction is extremely difficult.

3. Coal

TECHNOLOGICAL PROCESSES

Coal is the most abundant mineral in the United States. It has been mined in the eastern U.S. since the late 18th century, but emphasis is changing and the vast coal deposits of the Rocky Mountain region are growing in importance.¹⁾

Coal is mined in the U.S. by two primary methods: (1) strip mining, also called surface or open pit mining, and (2) underground mining. The mining method employed is based mainly on the amount of overburden overlying the coal seam although other considerations include topography and surface area required for mine wastes and processing equipment.

Strip mining can be classified into two major types: (1) contour mining which is employed in hilly or mountainous terrain where the hillside or slope limits the width of the potential area to be mined and (2) area mining, a technique employed when the coal seam lies flat thereby allowing the coal to be mined in a succession of pits or open cuts.

¹⁾ U.S. Bureau of Land Management, Proposed Federal Coal Leasing in the U.S., Section I, 1973, p. 33.

When coal properties permit strip mining, large tonnages may be mined by pits advancing across consolidated mining areas. Large capacity shovels and draglines are used in this situation to achieve maximum efficiency of large-scale operations. In contour strip mining the trend in equipment has been toward smaller draglines and shovels as compared to the trend toward larger equipment in area strip mining. The reason is that contour mining which takes place in hilly terrain requires greater mobility of equipment whereas the relatively flat terrain of area mining can tolerate larger equipment. Strip mining by its nature involves a continuous shift in mining site; therefore, it lends itself to the use of trucks to haul the coal from the point of extraction to the preparation plant. The National Petroleum Council shows the extent of contour versus area mining methods in the Eastern United States in the following table.^{1/} In the Western states, area mining is the primary form of surface recovery.

^{1/} Reproduced from National Petroleum Council, U.S. Energy Outlook, 1972, p. 159.

TABLE III-1
CONTOUR AND AREA MINING
AS A PERCENTAGE OF SURFACE MINING
(Surface Regions 1 Through 3)

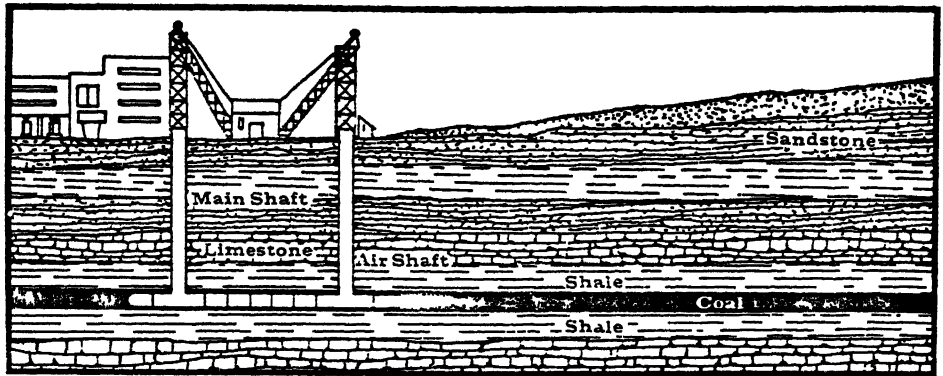
<u>State</u>	<u>Contour (Percent)</u>	<u>Area (Percent)</u>
Region 1		
Kentucky	20	80
West Virginia	90	10
Virginia	90	10
Tennessee	100	0
Region 2		
Illinois	0	100
Ohio	25	75
Indiana	0	100
Iowa	0	100
Region 3		
Pennsylvania	25	75

Three types of mines are used for underground mining: (1) shaft mines, (2) drift mines, and (3) slope mines. The type of underground mine employed depends primarily on the attitude and thickness of the coal seam as well as the depth of overburden. Figure III-1 shows the three types of underground mines as well as a surface mine. 1/

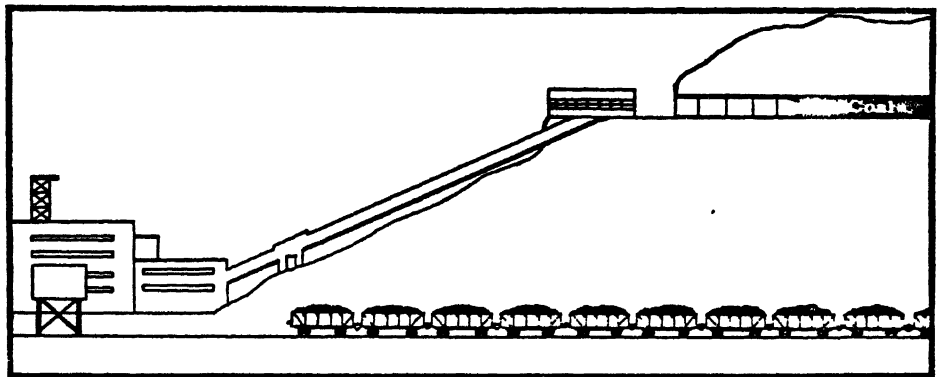
1/ Reproduced from National Coal Association, Bituminous Coal Facts, 1972, p. 17.

FOUR TYPES OF BITUMINOUS COAL MINES

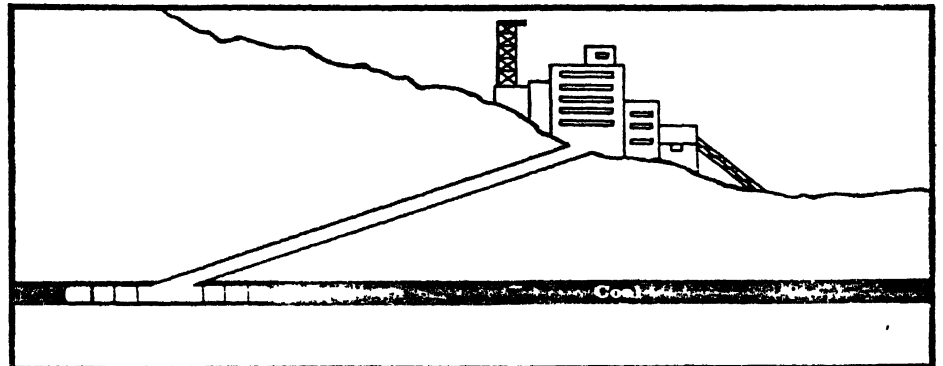
Shaft Mine



Drift Mine



Slope Mine



Surface Mine

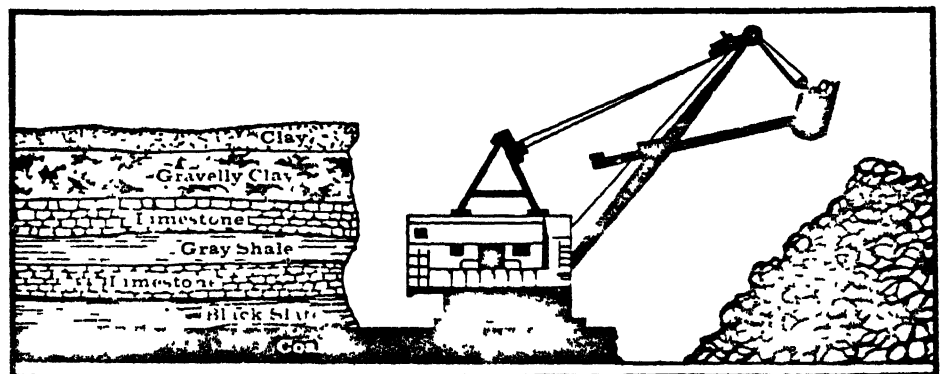


Figure III-1

Once coal is mined, it is sized, crushed and separated. Following processing, the coal is transported by rail, water carrier, or truck to its purchaser.

Significant advancements in the mechanization of coal mining and modes of transportation have enabled the coal industry to reverse a downward trend in production that reached its nadir in 1961 and to regain a substantial position in the Nation's expanded energy market in the face of very stiff competition from hydrocarbon fuels. Technological advancements have been particularly noteworthy in underground mining with the development of continuous mining machines and mechanized loaders. Mining machines combine into a single operation the breaking of coal from the coal face and its subsequent loading into conveyers or into shuttle cars or mine cars. Complementing the development of the continuous miner has been the technique of roof bolting. The use of roof bolts has replaced the old method of using wooden props to support the mine ceiling. As the mining progresses, holes are drilled in the ceiling and long expansion bolts are inserted and tightened so as to bind the overlying strata and thereby secure the roof.^{1/}

^{1/} Hunter, Thomas W., "Bituminous and Lignite," U.S. Bureau of Mines, Mineral Facts and Problems, 1970, pp. 39-41.

Mining at the surface also has undergone technological advances. The trend has been toward larger and larger machines; shovels capable of taking "bites" of 210 tons, draglines that can handle 120 cubic yards of earth at one time, and huge trucks that can hold 240 tons-the equivalent of 2 railroad cars.

Auger mining has come into use where a coal seam continues under strata that have become too thick for surface mining techniques, but do not warrant the construction of an underground mine. The auger miner is operated by one man who sits in an air-conditioned cab outside the mine. He controls the borers electronically and can drill 800 feet into the side of a hill to recover the coal as powered conveyor carts follow the augers into the hole and bring the coal to the adits for transport to the processing plant.

In the area of transportation, the concept of unit trains has drastically cut transportation rates and speeded the shipment of coal from the mine to the large consumer. Unit trains are strings of 100 or more high capacity coal cars loaded at the mine and shuttled directly to big consumers where they are dumped and returned for another load. Improvements in barge transportation include bigger barges and more powerful towboats to lower the cost of delivering coal. Moving coal by pipeline is possible but not prevalent.

Recent advancements in underground mining methods combined with a heightened awareness of mine health and safety requirements have spurred technological advances in coal mine safety. Typifying recent advances in the health and safety of coal mining have been the development of improved methane indicators, methods for reducing acid mine drainage, procedures for disposing of solid wastes, and sulfur removal processes. The removal of sulfur from coal poses a particularly difficult problem, especially when the sulfur occurs in forms that are not responsive to gravity separation. Recent developments in computer technology have been initiated to predict the sulfur and ash content of coal-in-place by computer analysis of core-hole sample analyses.^{1/} Similar studies have shown good possibilities of forecasting other properties of coal seams in place, prediction of low-temperature carbonization properties, and prediction of coal grindability.^{2,3,4} Application of this technique can lead to selective mining of uniform qualities of coal.

1/ Gomez, Manuel, and Hazen, Kathleen, "Evaluating Sulfur and Ash Distribution in Coal Seams by Statistical Response Surface Regression Analysis", U.S. Bureau of Mines, Report of Investigation, No. 7377, 1970.

2/ Gomez, Manuel, and Hazen, Kathleen, "Prediction of Coal Grindability From Exploration Data," U.S. Bureau of Mines, Report of Investigations, No. 7421, 1970.

3/ Gomez, Manuel, and Donaven, D. J., "Prediction of Low-Temperature Carbonization Properties of Coal in Advance of Mining," U.S. Bureau of Mines, Report of Investigations, No. 7681, 1972.

4/ "Forecasting the Properties of Coal Seams in Place", U.S. Bureau of Mines, Report of Investigations, No. 7680, 1972.

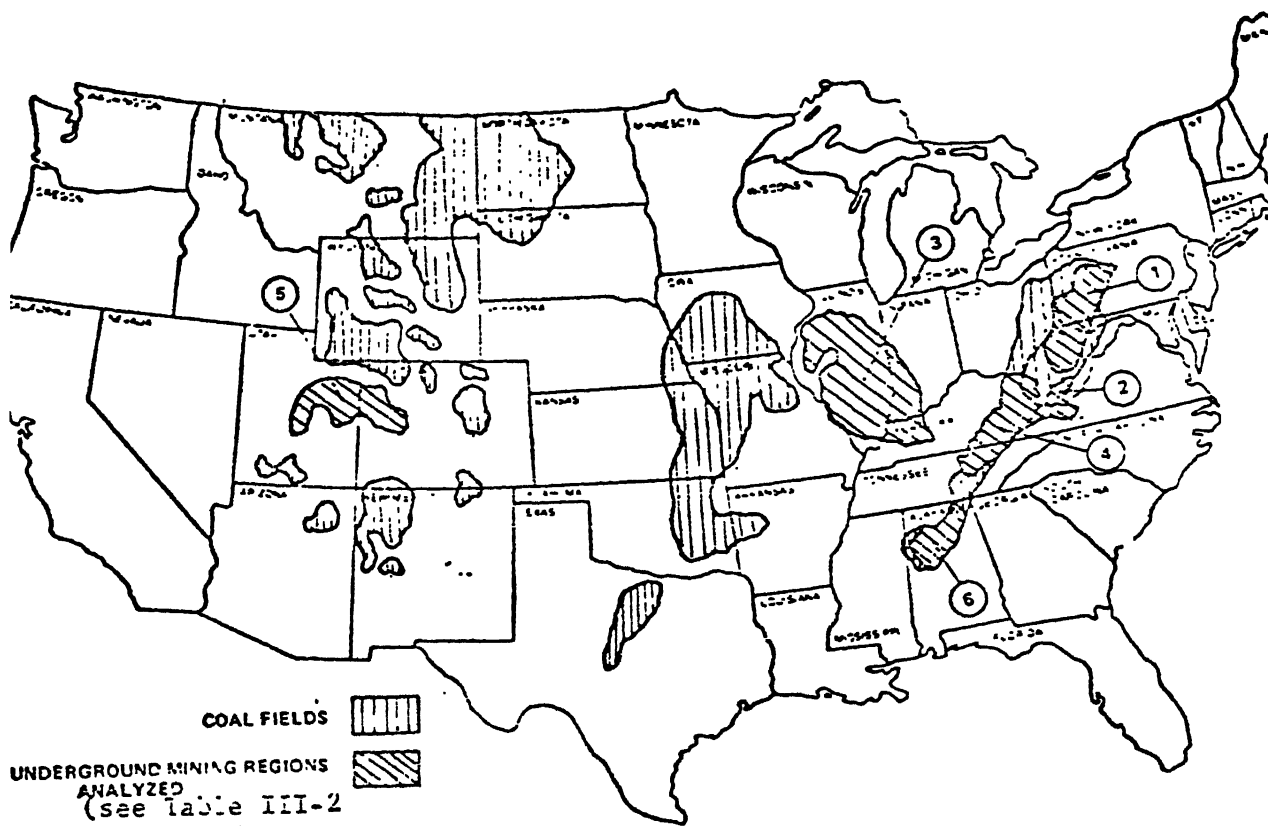
RESOURCE BASE

Coal is the only fossil fuel in which the nation is self-sufficient. The U.S. possesses total potential resources-in-place of 3.21 trillion tons, contains roughly 50% of the world's known supply, and has a ratio of recoverable reserves-to-production of 2,600.^{1/}

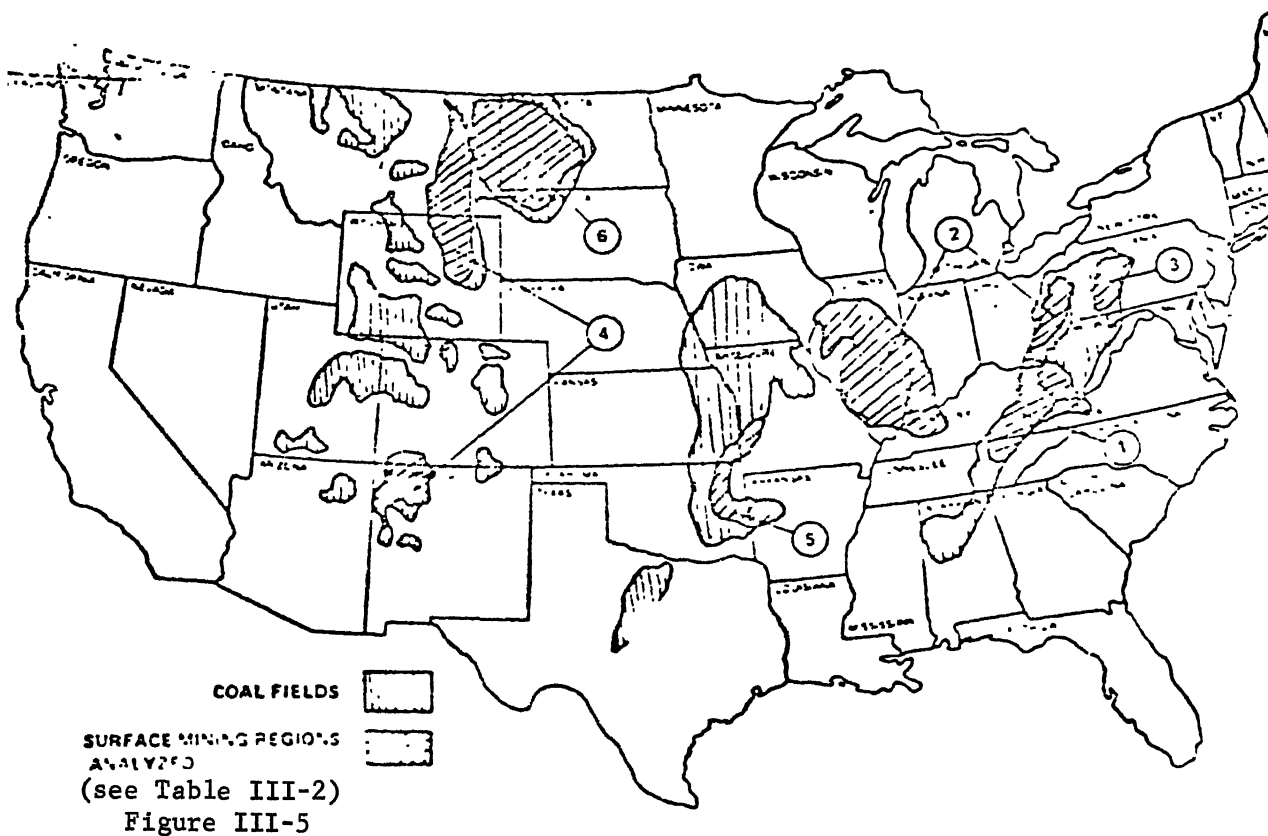
Maps prepared by the National Petroleum Council ^{2/} separate the domestic reserves into two categories--surface and underground mining regions. The mining regions outlined in figures III-4 and III-5 were selected in such a manner as to represent nearly equal proportions of surface and underground mines. A further subdivision was made of these major coal basins to segregate regions having uniform coal deposits and mining methods. A description of these regions is provided in Table III-2.

^{1/} Averitt, Paul, Coal Resources of the United States, 1967 (U.S. Geological Survey Bulletin 1275).

^{2/} Reproduced from National Petroleum Council, op. cit. pp. 139-141.



Coal Fields of the United States—Major Underground Mining Regions.



Coal Fields of the United States—Major Surface Mining Regions.

TABLE III-2^{1/}
COAL FIELDS OF THE UNITED STATES

Underground	Surface
Region 1	
1. West Virginia [*]	1. Kentucky
2. Pennsylvania	2. West Virginia
	3. Virginia
	4. Tennessee
Region 2	
1. Mercer County, W. Va.	1. Illinois
2. McDowell County, W. Va.	2. Indiana
3. Wyoming County, W. Va.	3. Iowa
	4. Ohio
Region 3	
1. Illinois	1. Pennsylvania
2. Indiana	
3. Ohio	
Region 4	
1. Kentucky	1. Colorado
2. Tennessee	2. Montana
3. Virginia	3. New Mexico
	4. Wyoming
Region 5	
1. Utah	1. Oklahoma
2. Colorado	2. Kansas
	3. Missouri
Region 6	
1. Alabama	1. North Dakota

^{*} Does not include Mercer, McDowell and Wyoming Counties in West Virginia, these three counties produce mainly low-volatile coking coal and are considered separately in Region 2.

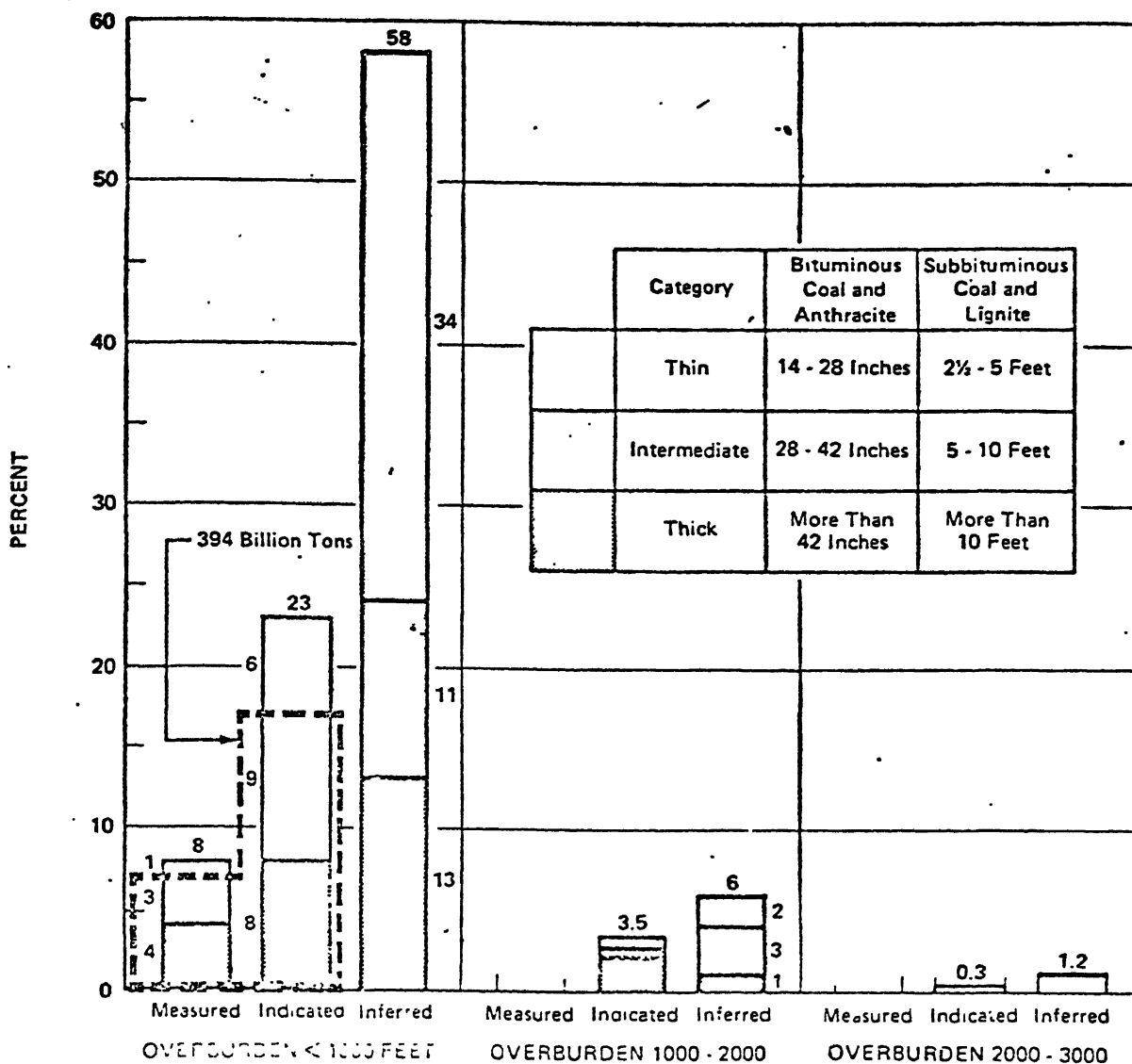
Further definition of the total coal-in-place figure of 3.21 trillion tons as computed by the USGS is reported as follows:

Mapped and Explored: 0-3,000' Overburden	1.56
Probable Additional Resource in	
Unmapped and Unexplored Areas: 0-3,000' Depth	1.31
3,000-6,000'	<u>.34</u>
Total	3.21 trillion tons

^{1/} Reproduced from NPC, op. cit., p. 140.

The National Petroleum Council further subdivides the percentage distribution of the 1.56 trillion tons at less than a 3,000-foot depth in the mapped and explored areas by depth, by seam thickness, and by three categories of certainty---measured, indicated, and inferred resources. The results of this analysis are presented in Figure III-6. The block within the dotted lines, representing 394 billion tons, shows "remaining measured and indicated reserves."

Figure III-6



NOTE: Coal overburden, Coal Resources of the United States, USGS Bulletin 1275 (January 1, 1967).

Figure III-6

Estimated Mapped and Explored Coal Resources—U.S.A. (Total Shown—1.56 Trillion Tons).

Reproduced from NPC, *op.cit.*, p. 142.

The National Petroleum Council provides further analysis of the "economically available reserves", measured and indicated reserves covered by less than 1,000 feet of overburden in Tables III-3 and III-4. It should be noted that in surface mining, the recovery factor is 80 to 89 per cent, whereas underground mining has only a 50-60 per cent recovery factor.

TABLE III-3
UNDERGROUND COAL RESERVES AND PRODUCTION
(Minable by Underground Mining Methods)

Region	Remaining Measured and Indicated Reserves*	Billions of Tons			1970 Production (Millions of Tons)	Life of Recoverable Reserves at % Growth Rate (Years)		
		Economically Available Reserves†	Recoverable Reserves‡	0%		3%	5%	
1	92.7	67.1	33.5	145.8	230	69	50	
2	9.1	9.1	4.6	N.A.	—	—	—	
3	83.1	59.5	29.7	52.3	568	96	68	
4	34.5	24.4	12.2	95.0	129	52	40	
5	21.9	13.3	6.7	8.6	774	106	74	
6	1.6	.6	.3	9.1	35	23	20	
Other	106.3	35.2	17.6	N.A.	—	—	—	
Total§	349.1	209.2	104.6	338.8	309	80	58	

* Bituminous, subbituminous and lignite in seams of "intermediate" or greater thickness and less than 1,000 feet overburden (see Figure 50).

† Excludes lignite and "intermediate" thickness seams of bituminous and subbituminous coal

‡ Based on 50-percent recovery of economically available reserves.

§ May not add correctly due to rounding.

TABLE III-4
SURFACE COAL RESERVES AND PRODUCTION
(Minable by Surface Mining Methods)

Region	Recoverable Reserves (Billions of Tons)	1970 Production (Millions of Tons)	Life of Reserves at % Growth Rate (Years)		
			0%	3%	5%
1	4.2	101.2	42	27	23
2	5.6	91.0	62	36	29
3	0.8	25.1	32	23	19
4	23.8	19.1	1,246	122	85
5	1.6	8.3	193	65	48
6	2.1	5.6	375	85	62
Other	6.9	13.8	500	95	67
Total	45.0	264.1	170	61	46

A National Petroleum Council summary of the status of known and potential coal resources is presented in Table III-5.

An examination of this tabulation indicates that the greatest coal potential lies in the Rocky Mountain region followed by the Midwest. The precise extent of the reserves must be delineated through an extensive core drilling program.

TABLE III-5				
SELECTED COMPARISON OF "MAPPED AND EXPLORED" AND "UNMAPPED AND UNEXPLORED" RESOURCE (Billions of Tons)				
	Total Resource	Mapped	Unmapped	Unmapped/ Total (Percent)
New Mexico	88	61	27	31
Utah	80	32	48	60
Colorado	227	81	146	64
Wyoming	445	120	325	73
Montana	379	222	157	41
North Dakota	530	350	180	34
Illinois	240	140	100	42
Indiana	57	35	22	39
Pennsylvania	20	70	10	13
West Virginia	102	102	—	—
Ohio	44	42	2	5

ECONOMIC CONSIDERATIONS

Cost and Prices

Coal prices vary depending on type of coal, mine location and mining method. For example, in 1971, strip mined bituminous coal used for steam power brought \$3.00 per ton at the mine, strip mined lignite brought \$1.65 per ton, and underground coking coal sold for about \$8.00 per ton. As demonstrated in the Bureau of Mines compilation of coal prices (Fig. III-7), the average f.o.b. mine price per ton has declined steadily in the last two decades.

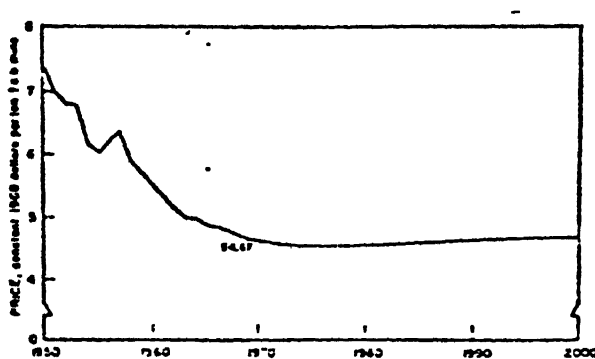


Figure III-7 Time Price Relationship for Bituminous Coal and Lignite

This notable price decline can be primarily attributed to increased efficiencies resulting from accelerated mechanization and a move toward strip mining in the coal industry. Competitive pressures on

coal have been maintained by the generally lower price of alternate energy sources and the keen intra-industry competition. These severe competitive pressures have prompted basic research into the technologies, methods, and procedures for achieving economies in coal production.

In making coal price projections, the Bureau of Mines has concluded that a continuing increase in strip mining, which exerts a generally downward influence on average coal prices and further increases in efficiencies at underground mines, will cause the f.o.b. mine value of coal to remain fairly stable on a constant dollar basis over time. ^{1/}

The following tabulation provides an approximation of operating costs for a new deep mine; costs are representative of 1970 levels but do not include cost increases resulting from the Coal Health Mine and Safety Act of 1969.

^{1/} U.S. Bureau of Mines, Minerals Facts and Problems, p. 46.

Direct Operating Costs
per Ton of Raw Coal

Labor (\$40 per day at 15 tons per man day)	\$2.65*
Supplies	1.75
Power	.18
Payroll Tax and Compensation	.20
United Mine Workers Welfare Fund	.40
Property Tax, Insurance, Misc.	.15
Direct Administration	<u>.10</u>
TOTAL	\$5.43

*The impact of productivity variations:

At 10 Tons per Man Day	+\$1.35
At 20 Tons per Man Day	- .65

Reproduced from National Petroleum Council, U.S. Energy Outlook, 1971, p. 135.

Transportation.

Representing about 40 percent of the delivered price of coal, transportation costs play a significant role in coal's competitive position with respect to petroleum and natural gas. The following chart shows bituminous coal transportation, by mode of transport.

Modes of Bituminous Coal Transport From Mines

(Thousands of Net Tons)

	Loaded at Mine for Shipment by Rail	Loaded at Mine for Shipment by Water	Shipped by Motor Vehicle	Used at Mine ¹	Total Production
1939.....	331,190	22,229	29,534	11,502	394,855
1940.....	380,388	29,493	35,540	15,350	460,772
1941.....	425,184	30,240	40,056	18,670	514,149
1942.....	482,814	34,018	45,154	20,706	582,693
1943.....	495,864	30,188	42,433	21,693	590,177
1944.....	527,135	31,518	40,123	20,799	619,576
1945.....	490,472	27,548	41,477	18,120	577,617
1946.....	450,616	24,642	42,731	15,935	533,922
1947.....	527,282	29,803	55,859	17,680	630,624
1948.....	498,194	26,735	58,260	16,329	599,518
1949.....	356,602	21,828	47,787	11,651	437,868
1950.....	417,224	27,584	58,286	13,217	516,311
1951.....	430,387	29,984	58,132	15,162	533,665
1952.....	375,911	27,746	50,231	12,953	466,841
1953.....	362,133	35,648	47,102	12,408	457,290
1954.....	305,918	32,912	44,689	8,187	391,706
1955.....	355,924	47,476	51,607	9,626	464,633
1956.....	390,015	50,732	49,768	10,359	500,874
1957.....	380,471	51,171	50,334	10,728	492,704
1958.....	305,642	43,899	50,605	10,300	410,446
1959.....	300,763	45,954	52,564	12,747	412,028
1960.....	303,865	46,784	52,699	12,164	415,512
1961.....	293,546	46,348	51,044	12,039	402,977
1962.....	307,328	48,106	54,853	11,862	422,149
1963.....	333,989	50,664	60,901	13,374	458,928
1964.....	349,377	59,349	65,532	12,740	486,998
1965.....	371,544	60,289	68,302	11,953	512,088
1966.....	386,958	62,092	67,026	17,805	533,881
1967.....	404,525	66,972	62,003	19,127	552,626
1968.....	396,443	66,885	61,753	20,165	545,245
1969.....	397,863	71,037	66,030	25,575	560,505
1970.....	409,111	81,337	73,977	38,507	602,932
1971.....	382,201	58,817	60,323	50,851	552,192

¹ Includes coal used by mine employees, taken by locomotive tenders at tippie, used at mine for power and heat, coal transported from mine to point of use by conveyor or tram, coal made into beehive coke at mine, and all other uses at mine. For 1971, includes 47,727,000 tons used at mine mouth generating plants. Source: U S Bureau of Mines

Reproduced from National Coal Association, Bituminous Coal Facts, 1972, p. 91.

Improvements in methods of coal transport have been prime contributors to the increase in coal demand. Cost reductions have been realized for all of the major modes of transport--rail, water, and road.

Reduction in rail transportation costs has come about through the development of unit trains. This cost reduction has resulted in a more rapid and efficient handling of increased volumes of coal as shipped from the mine to the producer. A concomitant improvement in coal storage systems has resulted in a substantial reduction in manpower requirements and turnaround time.

A reduction in the overall costs of river transportation has been realized through increases in the size of barges and power of towboats. Further economies in the transportation cost of coal and coal-generated energy have been made through the adaptability of coal to transmission by coal-slurry pipelines and the potential for extra-high voltage (EHV) transmission of electricity over long distances from mine-mouth coal generating plants.

Supply-Demand Relationships

An evaluation of current and projected coal supply-demand relationships is strongly dominated by several factors:

- 1) Reserves of coal far exceed projected base for coal demand. The resource base for coal is large enough to accommodate a much faster demand growth rate, should such an increase be realized.

- 2) Coal has the facility to be transformed into the other fossil fuel forms such as synthetic natural gas and synthetic oil. The development of coal gasification and liquefaction will have an increasing influence on coal supply and demand.
- 3) The President's Energy Message of April 18, 1973, called for expanded development and utilization of our coal resources. The President supported the extension beyond 1975 for meeting secondary air standards related to the general welfare to encourage increased use of coal as opposed to oil or gas. He also urged state utility commissions to insure that utilities receive a rapid and fair return on pollution control equipment.
- 4) Sulfur removal technology will play an increasingly important role in the ability of the coal industry to conform to Government environmental, health and safety regulations.
- 5) Natural gas and oil currently enjoy a competitive advantage over coal in the energy market. This balance should continue until the technology of coal mining, health and safety, and land reclamation improves.

- 6) Active research and development is being carried out to improve the capacity of mining equipment, acid mine drainage control, the disposal of mining wastes (siltation of water, land quality, human aesthetics, dust control), the reclamation of strip-mined lands, the control of sulfur oxide emissions (by the physical separation of pyrite from coals and by flue stack scrubbers), and procedures to convert coal to synthetic pipeline gas and synthetic hydrocarbon liquids.
- 7) Manpower requirements may invoke a serious constraint on the production of coal; enrollment in mining engineering curricula has markedly declined in the recent past. However, enrollment appears to have increased in the past few years.

The reserves and ability to increase coal supply are available; whether substantial increases are realized will depend in large measure on these seven major factors. Broken down by PAD Districts, a tabulation of national coal demand is as follows:

TABLE III-6

U.S. COAL DEMAND BY PAD DISTRICTS
(Trillion BTU's)

	<u>1970</u>	<u>1975</u>	<u>1980</u>	<u>1985</u>
PAD District I	4,745	5,394	6,071	6,871
PAD District II	6,998	8,416	9,859	11,533
PAD District III	920	1,178	1,503	1,857
PAD District IV	279	416	642	854
PAD District V	<u>120</u>	<u>150</u>	<u>209</u>	<u>273</u>
TOTAL*	13,062	15,554	18,284	21,388

* These quantities are less than the total demand figures shown in Extract from Volume One because they do not include "Assumed Replacement for Shortfall in Other Fuel Supplies." The added quantities for coal, in terms of tons of coal, would be 30 million tons in 1975, 65 million tons in 1980 and 70 million tons in 1985.

Reproduced from: National Petroleum Council, (1971), U.S. Energy Outlook, p. 127.

The National Petroleum Council projects an increase in coal supply from present reserves under different growth rates as follows:

TABLE III-7

FUTURE COAL SUPPLY FROM PRESENTLY USED RESERVES
FOR CONVENTIONAL DOMESTIC MARKETS ONLY

	<u>Growth Rate</u> (Percent)	<u>1970</u>	<u>1975</u>	<u>1980</u>	<u>1985</u>
Trillion BTU's per Year					
Case I	50	13,062	16,650	21,200	27,100
Cases II/III	35	13,062	15,554	18,284	21,388
Case IV	30	13,062	15,100	17,550	20,300
Million Tons per Year					
Case I	50	519	665	851	1,093
Cases II/III	35	519	621	734	863
Case IV	30	519	603	705	810
Average:					
Thousand BTU. Ton		25,167	25,046	24,910	24,783

Reproduced from: National Petroleum Council, (1971), U.S. Energy Outlook, p. 1

ENVIRONMENTAL IMPACT

Impact on Air Quality

The addition to the atmosphere of sulfurous gases is the primary harmful effect of the mining and consumption of coal. Sulfur dioxide may enter the atmosphere both when coal is mined, exposing pyrite (iron pyrite FeS_2), and following the combustion of coal as stack gas (sulfur dioxide, SO_2). Sulfur dioxide is present in the atmosphere in much smaller quantities than carbon dioxide and carbon monoxide but is far more toxic. SO_2 does not accumulate in the atmosphere because it converts to sulfuric acid and sulfates; the atmospheric life of SO_2 is generally a few days. In the presence of oxygen, sunlight, and water vapor, SO_2 converts to SO_3 and then to H_2SO_4 (sulfuric acid). In addition, prolonged exposures to SO_2 can cause corrosion and etching of various building materials, particularly copper alloys and building stone, concrete, and mortar containing carbonate.^{1/}

The sulfur content of U.S. coals ranges from 0.5 to over 7 percent. Bureau of Mines tabulations indicate that 46 percent (720,060 million tons) of the nation's total known coal resources under less than

^{1/} Air Conservation Commission, Air Conservation Report, 1965.

3,000 feet of cover contain 0.7 percent or less sulfur. Of this low sulfur content coal, 93 percent is located in the States west of the Mississippi River; for States east of the Mississippi, only 11 percent of the resources contain 0.7 percent or less sulfur. Of this 11 percent, much of the resources are low or medium-volatile coal which is used primarily for metallurgical purposes or in steel making. Compounding the problem is the fact that current transportation costs and facility limitations prevent the commercial movement of these reserves to eastern markets.

The following tables^{1/} provide a more detailed picture of the sulfur content of remaining domestic coal resources.

TABLE III-8

ESTIMATED REMAINING COAL RESERVES OF
ALL RANKS BY SULFUR CONTENT IN
THE UNITED STATES*

	Million Tons	Percent
0.7% or Less Sulfur	720,050.0	46
0.7% - 1.0% Sulfur	303,573.4	19
1.0% - 3.0% Sulfur	238,374.0	15
Over 3.0% Sulfur	314,159.0	20
Total	1,576,156.4	100

* As of January 1, 1965.

TABLE III-9

ESTIMATED REMAINING COAL RESERVES OF
ALL RANKS BY SULFUR CONTENT IN STATES
EAST OF THE MISSISSIPPI RIVER*

	Million Tons	Percent
0.7% or Less Sulfur	50,062	11
0.7% - 1.0% Sulfur	45,219	9
1.0% - 3.0% Sulfur	177,281	37
Over 3.0% Sulfur	206,495	43
Total	479,057	100

* As of January 1, 1965.

^{1/} Reproduced from : National Petroleum Council, U.S. Energy Outlook
1972, p. 160.

TABLE 111-10 ^{1/}	
STATES WITH LARGEST COAL CONCENTRATIONS OF 0.7 PERCENT OR LESS SULFUR	
<u>State</u>	<u>Million Tons</u>
Alaska	71,115.6
Montana	154,298.9
New Mexico	38,735.0
Wyoming	35,579.7
North Dakota	284,129.1

Coal, especially high-sulfur coal, is available in large quantities in close proximity to consuming markets. New coal burning plants could be built if air quality standards can be met but economics for coal desulfurization are marginal and optimistic assessments of economics are generally based on a substantial credit for sale of byproduct sulfur. Recently, the supply of sulfur has exceeded demand and the market cannot be expected to accomodate additional volumes from coal desulfurization.

Recent environmental regulations applicable to new electric generating facilities restrict the emission of sulfur dioxide to 1.2 pounds per million btu of fuel as fired; for bituminous coal, this is equivalent to about 0.7 percent sulfur. It is necessary, therefore, to reduce

^{1/} Reproduced from: National Petroleum Council, U.S. Energy Outlook, 1972, p. 160.

the sulfur content of the coal prior to burning, or to remove sulfur oxides from stack gases following combustion in order that coal may continue to be used for power generation.

Mechanical cleaning of raw coal is not a solution to the problem, since only a small fraction of American coals can be cleaned sufficiently to meet sulfur emission controls and standards.

Mechanical cleaning affects only pyritic sulfur and leaves untouched the 40 to 60 percent of the sulfur that is bound in the organic structure of the coal. In addition, freeing the small particles in which pyrites occur requires fine grinding prior to cleaning which, in turn, adversely affects the cleaning efficiency and restricts the methods of cleaning that can be applied.

Impact on Water Quality ^{1/}

The major damaging environmental impacts of coal mining on water quality consist of acid mine drainage, runoff from mined surface areas and siltation of water courses through the erosion of refuse sites. Of these problems, acid mine drainage is most acute and it is more prevalent in eastern states where sulfur contents of coal are higher.

^{1/} Flawn, Peter T., Environmental Geology, 1970, p. 313.

Acid mine drainage is formed from the mining of coal in the following manner. Stripping of coal seams exposes to air and water large quantities of rock high in iron sulfides (pyrite, FeS_2). On oxidation, the pyrite breaks down forming ferrous sulfate, ferric sulfate, ferric hydroxide, and sulfuric acid. The pH of exposed soil banks is often as low as three. (Values of pH vary from 0 to 14 with the low range indicating acidity the high range indicating alkalinity.) Until the pyrite has been oxidized and the acids leached from the soil, the high acidity inhibits the growth of vegetation. Experiments conducted by the Bureau of Mines on the revegetation of backfill strip mines demonstrated that, by applying lime to the soils, the pH of waters rose to 4.5, a decrease in acidity, increasing the survival of many plant species.^{1/} Because of retarded plant growth on soil banks, the banks are subject to rapid erosion and streams are subject to increasing loads of sediment. The negative effects of acid mine drainage can be thwarted by the containment and treatment of acid waters and stabilization of soil banks followed by grading and replanting of the stripped, mined-out areas.

^{1/} Magnuson, M. O., and Kimball, R. L., "Revegetation Studies At Three Strip-Mine Sites In North-Central Pennsylvania", U.S. Bureau of Mines, Report of Investigations, No. 7075, 1968, p. 8.

Ground and surface waters entering active underground mine workings are normally pumped to the surface for disposal. Because of the low-sulphur content of most Rocky Mountain coals, it is uncertain whether acid-mine water would be a problem in areas of large-scale mining and low average precipitation. Drainage of acid-mine water may be prevented by locating mine entries at elevations above the prevailing drainage level, by sealing abandoned mine entries, and by emplacing dams at critical points in abandoned underground entries and haulageways. The key to eliminating mine drainage is to prevent formation of acid waters. This is difficult, however, because mine drainage can occur in many different forms and with many different compositions, under conditions as diverse as the coal rap. Ongoing research and strife against mine drainage involves the use of infrared photography to detect acid mine water flows and new techniques for sealing up abandoned mines. Results of mine-sealing techniques developed over the past 50 years, including bulkheading, grouting air'entries, injecting gel and slurry sealants, and using heavier-than-air vapors have been mixed; in some cases, sealing has been successful and, in other cases, it has not. For example, the Environmental Protection Agency reported that its mine-sealing demonstration project at Elkins, West Virginia, did not reduce oxygen concentrations in the mines or decrease the pollution load. Preventing

drainage in underground coal mines is still the topic of many research projects; surface mining, fortunately, enables drainage prevention measures that are almost 100% successful. ^{1/}

Most coals contain undesirable constituents and must be cleaned.

It is assumed that, under ideal conditions, a five percent cleaner loss would occur. This problem may not be critical for surface mines where pits, from which the coal would be extracted, could receive this material. Ultimately, the mine pits would be backfilled, levelled, the top soil replaced, and the area reseeded. The problem of siltation is not as severe for Rocky Mountain area coal fields which require little preparation before use.

Construction of slurry impoundments on underlying previous bedrock may result in pollution of the ground water. Percolation through the base of dikes permits slurry water to reach downstream drainage systems. Unless measures are taken by coal operators to seal this type of disposal area, unfavorable impacts can continue for decades. However, use of appropriate treatment methods on the part of coal operators, coupled with effective enforcement of waste disposal regulations promulgated by State and Federal Governments, can minimize such effects on the environment.

^{1/} National Coal Association, op. cit., p. 26.

Impact on Land Quality

Open pit mining disturbs a considerable amount of surface acreage. As of 1967, it is reported that open pit coal mines were responsible for 41 percent of the land disturbed by surface mining in the United States. ^{1/}

As an example, predictions regarding the total size of the areas which would be disturbed by the surface mining of about 20,000,000 short tons of coal are shown in the following table.

Table III-11

PRODUCTION BY SURFACE MINING METHODS

(BASED ON 1,800 TONS PER ACRE FEET)

(FIGURES BASED ON 20,000,000 TONS PRODUCTION ANNUALLY OVER 5-YEAR PERIOD)

Coal Bed Thickness (Feet)	Recovery Factor (%)	Coal Avail. per sq. mi. @ 80% Rec. (Tons)	Area Disturbed Annually (sq. mi.)	Area Disturbed (sq. mi.)
10	80	9,216,000	2.3	11.5
15	80	13,824,000	1.5	7.5
20	80	18,432,000	1.1	5.5
25	80	23,040,000	0.9	4.5
30	80	27,648,000	0.8	4.0
35	80	32,256,000	0.7	3.5
40	80	36,064,000	0.6	3.0
45	80	41,472,000	0.5	2.5
50	80	46,080,000	0.5	2.5

^{1/} U.S. Dept. of the Interior, Surface Mining and Our Environment, A Special Report to the Nation, 1967, p. 53-54.

Climate conditions are extremely important in considering the rehabilitation of mined lands. Without proper moisture the reseeding of reclaimed lands would serve little purpose and erosion processes would soon destroy the contour of the rehabilitated lands. This problem is greater in the Western states than in the East. The following table shows the rehabilitation cost on a per ton basis for varying degrees of restoration.

Table III-12
ESTIMATED COSTS IN CENTS PER TON OF COAL FOR REGRADING, RESEEDING,
AND REVEGETATING STRIP-MINED LANDS TO A PLEASING, NATURAL CONTOUR

Assumed tonnage of coal recovered per acre	Estimated costs of reclamation per acre (dollars)				
	\$1,000	\$2,000	\$3,000	\$4,000	\$5,000
10,000	.10	.20	.30	.40	.50
20,000	.05	.10	.15	.20	.25
30,000	.033	.066	.10	.13	.17
40,000	.025	.05	.075	.10	.13
50,000	.02	.04	.06	.08	.10
100,000	.01	.02	.03	.04	.05

In underground mining, subsidence of the ground surface is common above any abandoned and some active coal mines. The amount of subsidence relates to the mining method employed, the amount of coal

removed, the thickness of the coal bed, the thickness of cover, and the composition and strength of rocks overlying the coal. Subsidence of large areas commonly destroys man-made structures, disrupts the ground water hydrology, cuts off surface and subsurface water recharge, adversely affects the quality of underground and surface waters, redirects the planned drainage of a mine, disrupts surface drainage, and, in periods of heavy rainfall, localizes flooding. It also causes land slides in some localities. The best solution for subsidence may be to achieve as complete recovery of coal as possible during mining, then allow controlled subsidence to the point of natural stabilization and then, to develop the land surface. This is made possible in a method of mining called longwall mining, a system imported from Europe. Longwall mining employs a steel-tipped plow on a whirling planer that is pulled across a working face several hundred feet long, shaving off coal from the seam. The loosened coal falls into a conveyor. The distinguishing feature of longwall mining in regard to subsidence is this: large self-advancing hydraulic jacks set a few inches apart support the roof and follow the machine as it moves deeper into the coal. As the jacks move forward, the mine roof is allowed to collapse behind them. Thus, subsidence occurs almost immediately under a planned system thereby lessening the harmful impacts that could result from uncontrolled

subsidence. Although longwall mining has only recently been introduced into U.S. coal mining it shows great promise for eliminating or lessening the subsidence problem.^{1/}

In addition to problems associated with land subsidence, another serious land quality problem associated with underground mining is disposal of mining wastes.

The volume of mine wastes depends on the mining method employed, the type and characteristics of top and bottom strata, the continuity of coal beds, the tonnage mined, the amount of waste material included, the specifications for which coal is being prepared, and the efficiency of processing equipment. Because costs are incurred whenever wastes are moved, mine waste piles accumulate as close to the mine mouth or open pit as possible. If these wastes are contained, either by the natural terrain or by engineering design, the main environmental effect is a man-made hill, a minor addition to topography. However, if large amounts of unconsolidated materials are allowed to accumulate without proper engineering supervision, they may become unstable and subject to mass movement. A slide in a mountain of coal mine wastes at Aberfan, Wales, in October 1966, destroyed a school and took many lives.

^{1/} National Coal Association, op. cit., p. 13.

An additional problem with coal mining wastes concerns dust from debris piles. The most commonly used technique of preventing widespread scattering of mining and processing wastes is compacting the waste layers, followed by sealing with incombustible soil, after which vegetation is established to prevent infiltration of surface water and to minimize erosion. An alternative to surface disposal of mine and coal processing waste is to return wastes to abandoned underground mine workings. This is currently being done to control surface subsidence in mined areas in compliance with restoration provisions of the Appalachian Regional Development Act of 1965, as amended. Methods of returning the waste to mined out areas concurrent with active mining would appear to warrant attention of mining method researchers.

Finally, the loss of a potential resource by fire poses a hazard in underground mining. Under certain circumstances, air may reach the coal seam and activate the coal to the point of combustion. By whatever means a fire starts, once it starts, it continues to burn until it reaches either the limit of coal or a fault in the coal seam. Severity of the coal fire hazard decreases with depth.^{1/}

^{1/} U.S. Bureau of Land Management, *op. cit.*, p. 91.

RELATIONSHIP OF ALTERNATIVE TO PROPOSED OCS SALE

To replace the expected energy from the proposed Texas OCS #34 sale (0.96 to 1.62 trillion Btu/day) with energy from coal would require the utilization of 15 to 25 million tons of coal per year. An increase of this magnitude could be supported by existing U.S. proved reserves. The primary constraints would be economic and environmental.

If this increased coal were provided by surface mining, it is believed that 3-5 mines of five million short tons annual capacity would be needed. One mine of this size would employ about 600 persons and have a capital cost of \$40 million. To supply the necessary incremental amount would require 1,800 to 3,000 employees and capital expenditures of 120-200 million dollars.

If underground mines were used, 7-12 mines of 2 million tons annual capacity would be required. Manpower for these operations would be 11,800 to 20,200 and capital expenditures would range from \$161 to \$276 million.

If the energy for this sale came from surface mined coal, the major consideration would be the amount of land disrupted. The following table gives an indication of how much land would be disturbed in the surface mining of 25 million tons/year.

Land Disturbed In Surface Mining Production

(Figures Based On 25 Million Tons Produced Annually)

<u>Coal Bed Thickness (feet)</u>	<u>Recovery Factor (%)</u>	<u>Coal Available (million Per Sq. Mile tons)</u>	<u>Area Disturbed Annually (Sq. Mi.)</u>
10	80	9.216	2.7
15	80	13.824	1.8
20	80	18.432	1.3
25	80	23.040	1.1
30	80	27.648	0.9
35	80	32.256	0.8
40	80	36.064	0.7
45	80	41.472	0.6
50	80	46.080	0.5

4. Synthetic Sources of Oil and Gas

A. Oil Shale

TECHNOLOGICAL PROCESSES

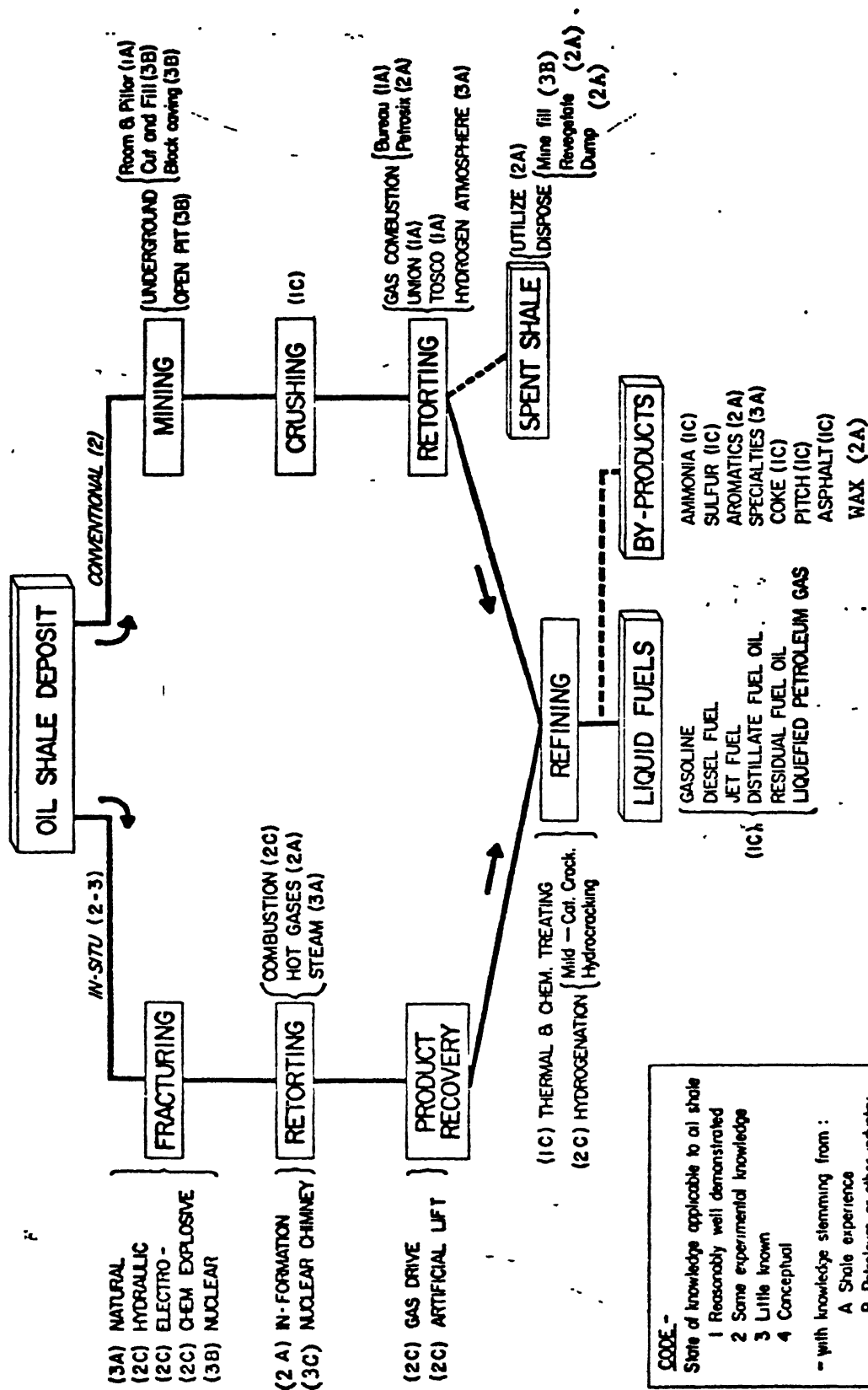
U. S. has abundant oil shale resources that offer great potential to supplement conventional supplies of oil and gas. These resources have not been developed in the past because of availability of oil and gas from conventional sources at lower development costs. However, present and projected energy shortages have focused attention on the energy promised by oil shale.

The major options for oil shale development are: (1) mining followed by surface processing of the oil shale and shale-oil; and (2) in-situ (or in place) processing. The relative state of knowledge of the various operations required in oil shale processing is shown in Figure IV-2 1/.

Until recent years, virtually all efforts to develop oil shale technology were directed toward mining, crushing, and above-ground retorting. Oil shale processing in this manner would require the handling of large amounts of materials. Figure IV-2 indicates the materials flow through

1/ Most of the refining operations shown in Figure IV-2 would be performed outside of the oil shale region at refinery centers near markets for the products. Figures IV-1, IV-2 and IV-3 are from the Final Environmental Statement for the Prototype Oil Shale Leasing Program, U. S. Department of the Interior, August 1973, Volume 1.

Figure IV-1. Relative State of Knowledge of Various Operations Required in Oil Shale Processing



CODE:-
 State of knowledge applicable to oil shale
 1 Reasonably well demonstrated
 2 Some experimental knowledge
 3 Little known
 4 Conceptual
 - with knowledge stemming from :
 A Shale experience
 B Petroleum or other industry experience
 C Both

such an operation, beginning with mining and ending with final fuel products and various by-products. In certain locations, the oil shale deposits contain minerals that may be amenable to recovery of additional by-products such as soda ash and alumina.

Oil shale mining can be conducted either at the surface or underground. The former, usually described as open-pit mining, involves removal and disposal of the surface material or overburden, followed by mining the underlying oil shale in a quarry-like operation. The quantity of overburden significantly affects the development time and economics. Current open-pit techniques and existing large-scale equipment are expected to enable mine development at relatively low costs, although disposal - restoration costs will be greater than similar costs for underground mining.

The room-and pillar method has been extensively tested for underground mining of oil shale. In this development plan the recovery rate would depend on the depth and local conditions. In general, about 60% of the shale can be removed. The remainder is left as pillars to support mines and to prevent surface subsidence. It is expected, however, that some mining operations would provide substantially lower total extraction percentages. Room-and pillar mining is characterized by large rooms over 60 feet in height, separated by the support pillars. Access to the oil shale to be mined can be gained from the surface either by a vertical shaft, or a horizontal adit or tunnel.

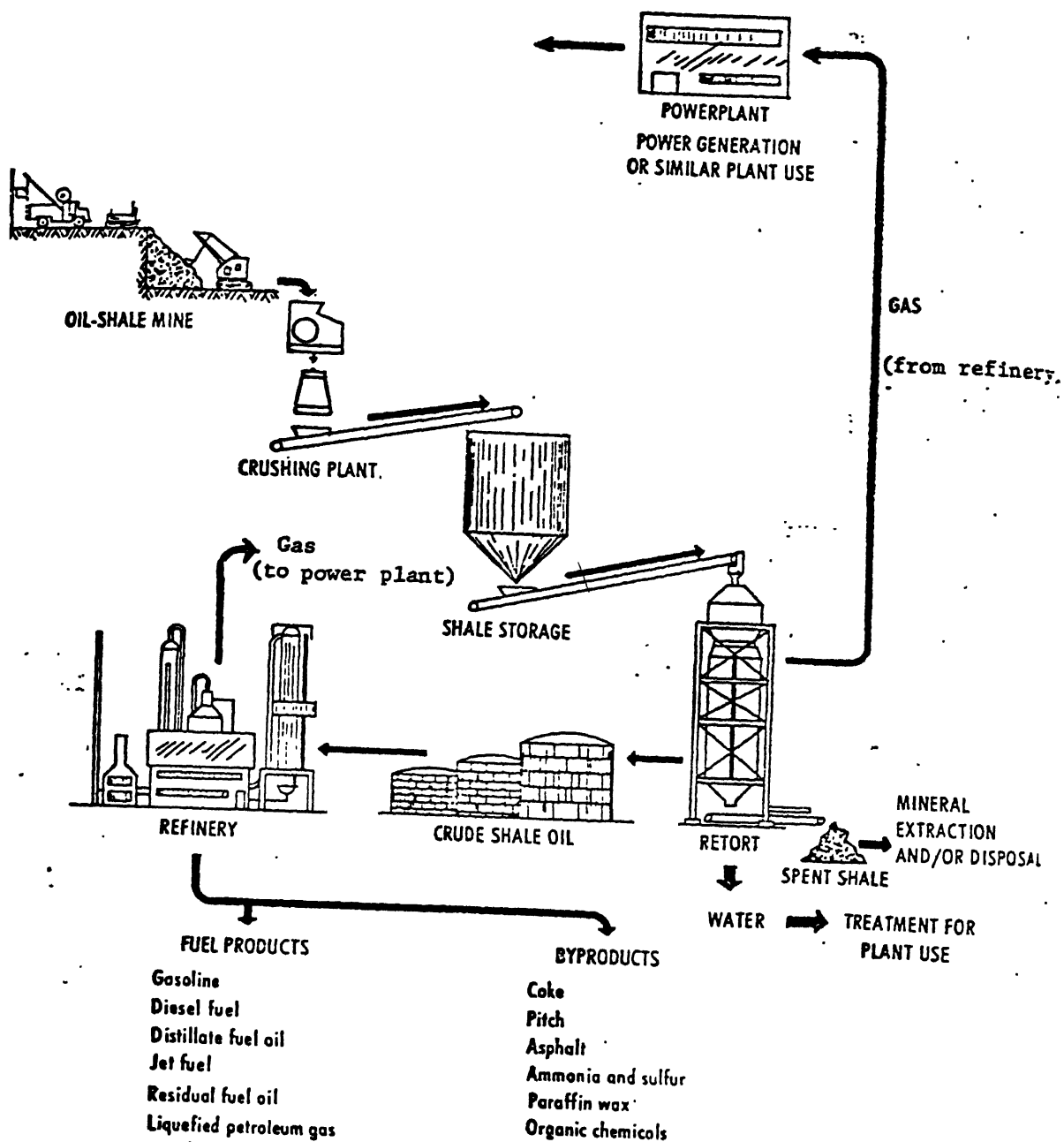


Figure IV-2. Schematic Diagram of Oil Shale Surface Processing

Crushing and conveying systems are technically and economically well-established and are regarded as necessary parts of any integrated processing system. The selection of specific equipment is primarily based on the size of the oil shale fragments needed for subsequent processing.

Literally thousands of retorting processes have been patented worldwide for the production of oil from oil shale. Three processes that have been tested using large experimental equipment appear at this time to offer reasonable possibilities of technical and economic success if scaled up to commercial design size. These retorting methods are the Gas-Combustion process developed by the Bureau of Mines, the Oil Shale Corporation (TOSCO) process, and the Union Oil Company process. In each system, heat is applied to raise the temperature of the oil shale to about 900 degrees F., where the solid organic material (kerogen) is converted to a liquid. The equipment, method of heat application, and operating procedures differ markedly for each system.

Oils from the retorting processes, with the possible exception of the TOSCO process, will require upgrading before the oil can be transported through pipelines to the final product refineries, which are expected to be located outside the oil shale region. Modern refinery processes are suitable for subsequent upgrading. Each of the three retorts also produces a retort gas that may be used within the plant as a fuel, or alternatively, to generate supplemental electrical power for nearby communities.

Spent shale may be in the form of solid particles ranging from 10 inches in diameter to a fine powder, depending on the retorting method used. It will normally be dry, but it may be wet if it is processed to recover saline minerals. Disposal will therefore depend on the physical characteristics of the material, its water content, and the location of the disposal area, whether surface or subsurface. If it is to be returned to the mine, this will affect the mine development plans.

Various processes for recovery of the saline minerals associated with the oil shales have been proposed.

The economical recovery of alumina, soda ash, and nahcolite (potentially valuable for removal of sulphur oxides from stack gases) from the deep oil shales has not yet been demonstrated on a large scale nor have the effects of their recovery been tested by current markets for these chemicals.

An alternate mining and processing technique, called in-situ processing, would involve the recovery of oil from the shale by heating underground, in place. Presently proposed heat sources for the in-situ recovery include underground combusting, hot natural gas, hot carbon dioxide, superheated steam, hot solvents, and combinations of two or more of these. It is anticipated that conduits for introducing heat underground would be provided by wells, mine shafts and tunnels, fractures created by a variety of techniques including nuclear explosives, or by a combination of these.

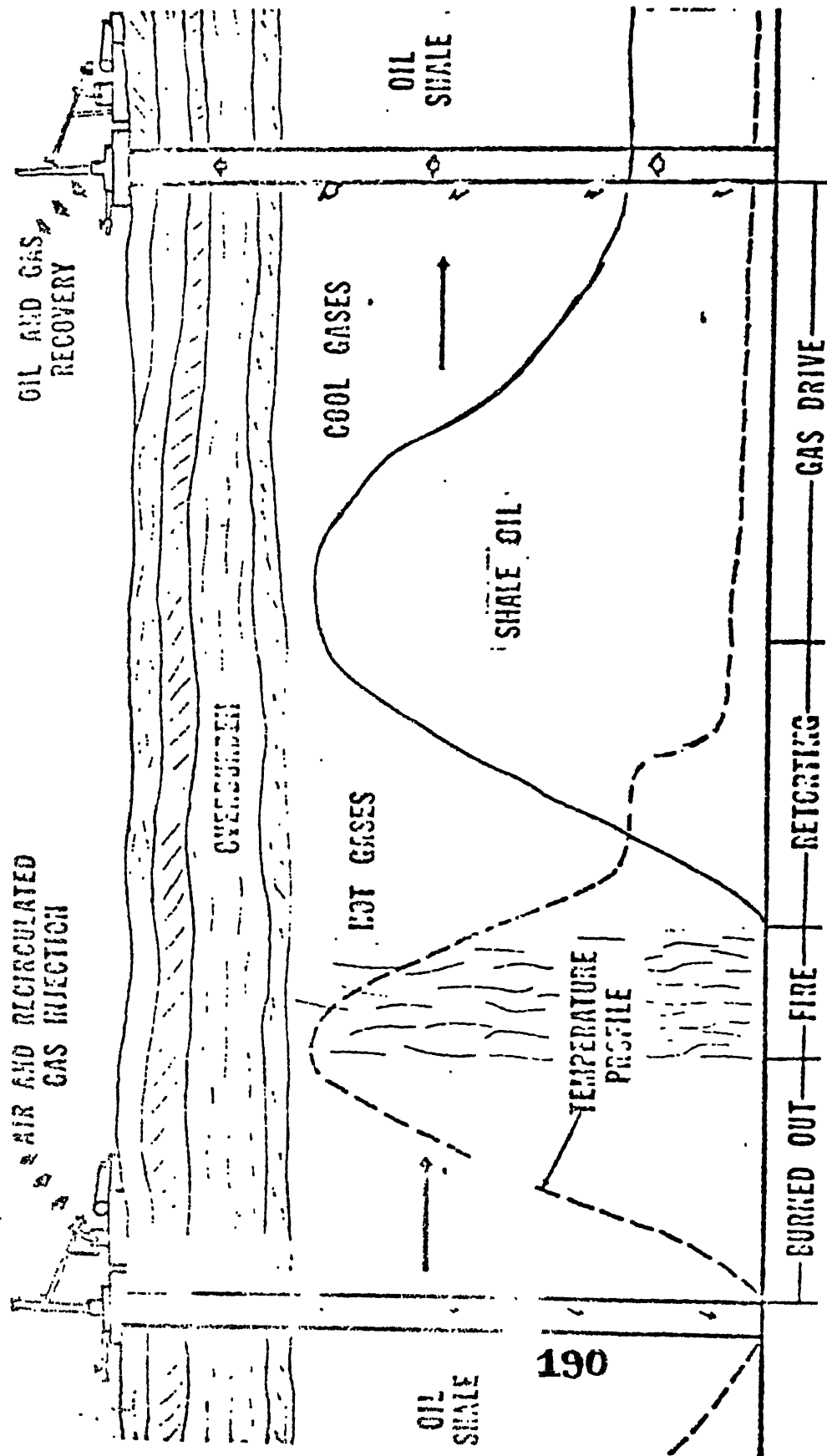


Figure IV-3-Schematic Representation of an In Situ Retorting operation

Figure IV-3 shows a design concept for conventional in-situ retorting based on contemporary petroleum technology. The essential steps include 1) well drilling, 2) fracturing to permit heat transfer and movement of liquids and gases, 3) application of heat, and 4) recovery of products.

Despite considerable laboratory and field research, in-situ processing has not been successfully developed or demonstrated on a large scale. Two problems have been 1) insufficient naturally occurring permeability, or failure to artificially induce permeability in order to permit heat transfer and passage of gases and liquids, and 2) inability to remotely control the process with sufficient accuracy through wellbores from the surface. Additional problems if nuclear explosives are used are possible ground motion and release of radioactivity.

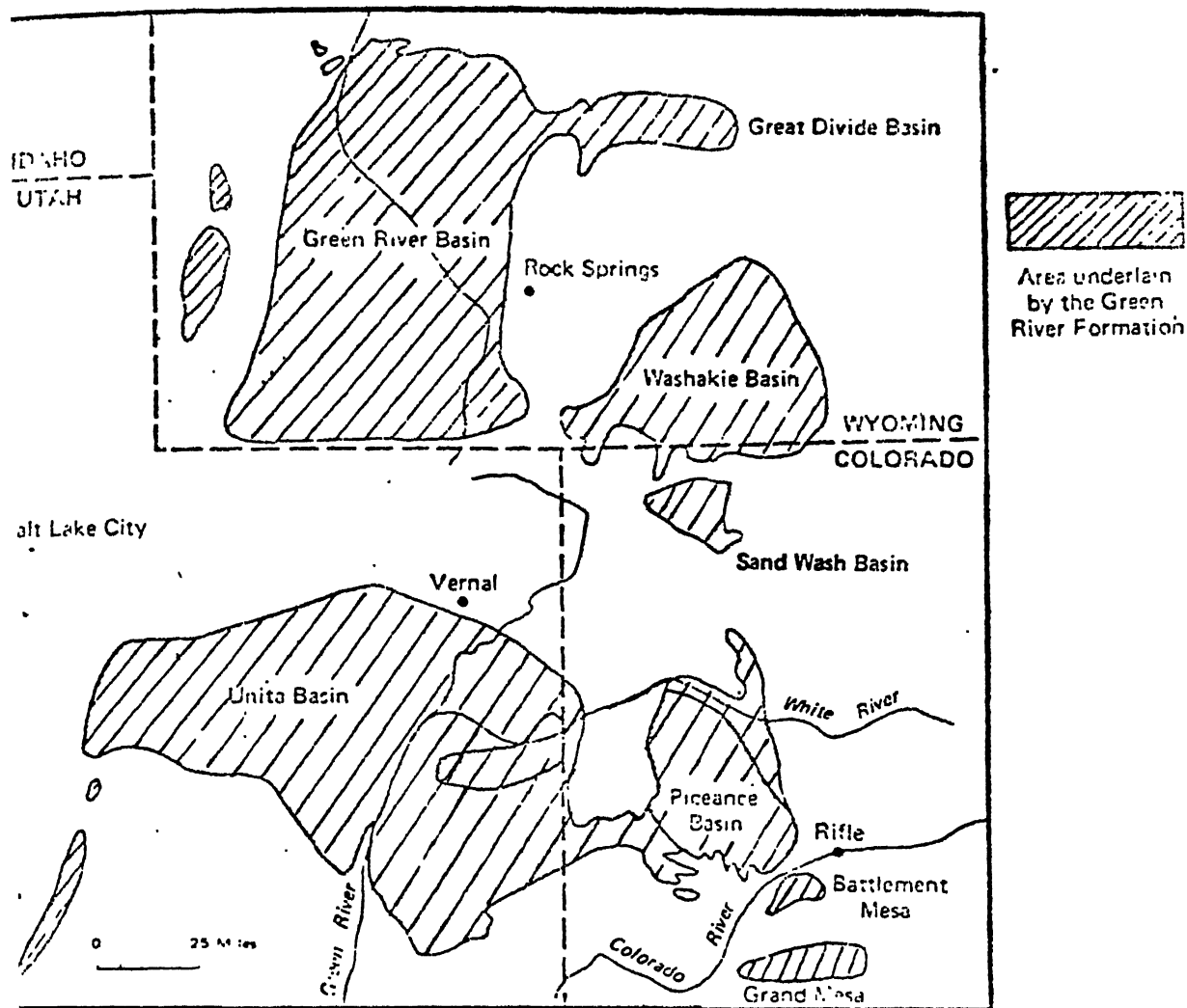
RESOURCE BASE

Oil shale deposits are found in many areas of the U.S. but many are low grade, small, and inaccessible. The richest deposits occur in the Green River Formation in Colorado, Wyoming, and Utah in large topographic basins that are identified by streams draining most of the land surface. These include the Green River Basin and Washakie Basin in Wyoming, the Uinta Basin in Utah, and the Piceance Creek Basin in Colorado. Oil shale of possible commercial interest also occurs in Battlement and Grand Mesas in Colorado. These oil shales are found beneath 25,000 square miles (16 million acres) of land and of which about 17,000 square miles (11 million acres) are

believed to contain oil shale with potential for commercial development. An estimated 73% of oil shale lands, containing nearly 80% of the Green River Formation resources, are federally held.

The Green River Formation contains known oil shales with about 600 billion barrels of equivalent oil in the higher grade deposits (averaging more than 25 gallons per ton and a minimum of 10 feet in thickness). Lower grade zones in the Formation (averaging 15 to 25 gallons per ton) contain an additional 1,200 billion barrels.

About 80% of the known higher grade resources are found in Colorado, 15% in Utah, and 5% in Wyoming. This region is sparsely settled and arid or semi-arid. Figure IV-4 shows the Green River Formation.



Source: U. S. Energy Outlook, A report of the National Petroleum Council's Committee on U.S. Energy Outlook, Dec., 1972.

Figure IV-4. Oil Shale Reserves of the Green River Formation.

The National Petroleum Council gives the following breakdown of reserves based on commercial attractiveness:

Classes 1 and 2. The most accessible and better defined of the deposits at least 30 feet thick and averaging 30 gallons of oil per ton of shale. Class 1 averages 35 gallons per ton over a continuous interval of at least 30 feet.

Class 3. Deposits as rich as Classes 1 and 2 but more poorly defined and not as favorably located.

Class 4. Low grade, poorly defined deposits.

Table IV-1

Oil Shale Resources of the Green River Formation

(Billion of Barrels)

Location	Class 1	Class 2	Class 3	Class 4	Total
Piceance Basin - Colorado	34	83	167	916	1,200
Unita Basin - Colorado & Utah		12	15	294	321
Wyoming			4	256	260
Total	34	95	186	1,781	

Source: U.S. Energy Outlook, A report of the National Petroleum Council's committee on U.S. Energy Outlook, Dec., 1972.

ECONOMIC CONSIDERATIONS

Projections of capital investment, prices of shale oil, and rate of development are dependent on each other and on assumptions concerning industry and government policies, technology, and required rates of return. The National Petroleum Council gives estimates of possible development under four sets of conditions. Case I represents the maximum feasible production under non-emergency conditions and assumes shale oil prices adequate to encourage commercial development. Limitations on rate of development include availability of operating personnel, environmental restrictions, lack of supporting commerce and industry, and construction logistics. Cases II, III, and IV show slower rates of in development due to lack of investment incentive or need for time to demonstrate process feasibility. Table IV-2 shows production rates under each set of conditions.

Table IV-2 - Production of Shale Oil (MB/D)			
	1975	1980	1985
Case I	0	150	750
Case II	0	100	400
Case IV	0	0	100

Source: U.S. Energy Outlook, Dec., 1972. p. 205.

Price predictions are sensitive to the rate of return desired and the shale assay. "Price" developed by the National Petroleum Council is exclusive of transportation costs to refineries (\$0.50 to \$0.75 per

barrel), leasing costs, or bonus payments. These prices are based on invested capital to build and equip two mines, two retorts, and one upgrading plant to produce 100 MB/day of shale oil. Table IV-3 shows these prices.

Table IV-3 Required Shale Oil "Prices"
(Dollars per barrel)

<u>Discount Cash Flow Rate of Return (%)</u>	<u>30 gallons/ton oil shale</u>	<u>35 gallons/ton oil shale</u>
10	4.32 - 4.47	3.97 - 4.09
15	5.58 - 5.79	5.10 - 5.29
20	7.03 - 7.29	6.45 - 6.72

Source: U.S. Energy Outlook, Dec., 1972. p. 206.

The detailed assumptions used in developing these projections are described in U. S. Energy Outlook. Prices will be influenced by royalty rates, depreciation and depletion allowables, and investment tax credit provisions.

On June 29, 1971, the Secretary of the Interior announced plans for a proposed prototype oil shale leasing program which would make available to private enterprise, for development under lease, a limited amount of public oil shale resources. Such leases would be by competitive bonus bidding and would include assumption of certain royalty obligations to the United States. Six tracts, two in Colorado, two in Utah, and two in Wyoming, have been selected for the program. One of the tracts

in Colorado was leased in January 1974 for \$210 million. The second Colorado tract was leased in February for \$117.8 million. Each of the remaining tracts will be offered at separate sales in the next few months.

The following excerpt from the final Environmental Statement for this program 1/ describes the rate of oil shale development that may be expected.

For purposes of the present discussion, it is assumed that private lands would support no more than 400,000 barrels per day and that the six prototype tracts would support a total of 250,000 barrels per day. The combined output from private and public holdings would then reach 650,000 barrels daily by 1985. Additional public lands would be required to increase the production rate above this level. Even if suitable lands are available, the rate of development will be determined by the logistics of plant construction and by manpower constraints. Under these constraints, the Department of the Interior estimates the maximum 1985 production to be 1 million barrels per day. Even at this rate of production, only about 9 percent of the 80 billion barrels of prime commercial interest would be produced by the year 2000. The ultimate size of the oil shale industry will most likely not be determined by the magnitude of the oil shale resource base but will probably be limited by other factors such as the availability of water, for example.

1/ Final Environmental Statement for the Prototype Oil Shale Leasing Program, released August, 1973 by the U.S. Department of the Interior, Vol. I, p. III-7.

ENVIRONMENTAL IMPACT

Impact on Land Quality

The development of an oil shale industry would require roads, mining, plant sites, waste-disposal areas, utility and pipeline corridors, and associated services during the productive life of a lease. These activities would change the existing pattern of land use, alter the existing topography and would affect natural vegetative cover until revegetative operations began. Such disturbances would unavoidably exist throughout the life of operations, but would be temporary in the sense that restoration of surfaces to original or improved condition would be required before site abandonment. Table IV-4 shows the amount of land that would be required for a 100,000 bbl./day surface mining operation, a 50,000 bbl./day underground mine operation, and a 50,000 bbl./day in situ operation.

Overburden and spent shale could be deposited in canyons and gullies which would gradually be converted into flatter areas. Contouring and revegetation would restore scenic attractiveness and probably reduce erosion.

Where areas to be developed are now used for livestock grazing, agriculture, wildlife habitat, or recreation, some unavoidable loss in these patterns of land use would result.

1/ This discussion is taken from the Final Environmental Statement for the Prototype Oil Shale Leasing Program, U. S. Dept. of the Interior August 1973.

TABLE IV-4 --- Land Requirements for Oil Shale Processing

<u>Function</u>	<u>Land Required (Acres)</u>
Mining and waste disposal:	
Surface Mine <u>1/2/</u> (100,000 bbl/day):	
Mine development.....	30 to 85 per year
Permanent disposal; overburden.....	1,000 (total)
Temporary storage; low-grade shale	100 to 200 (total)
Permanent disposal; processed shale.....	140 to 150 per year
Surface facilities <u>3/</u>	200 (total)
Off-site requirements <u>4/</u>	180 to 600 (total)
Underground Mine <u>2/</u> (50,000 bbl/day):	
Mine development (Surface facilities)..	10 (total)
Permanent disposal:	
All processed shale on surface.....	70 to 75 per year
60 percent return of processed shale underground.....	28 to 30 per year
Surface facilities <u>3/</u>	140 (total)
Off-site requirements <u>4/</u>	180 to 225 (total)
In situ processing (50,000 bbl/day):	
Surface facilities <u>3/</u>	50 (total)
Active well area and restoration area ..	110 to 900
Off-site requirements <u>4/</u>	180 to 600 (total)

1/ Area required is dependent upon the thicknesses of the overburden and oil shale at the site. Acres shown are for a Piceance Creek shale (approximately 900,000 bbl/acre).

2/ Assumes 30 gallons per ton oil shale and a disposal height of 250 feet.

3/ Facilities include shale crushing, storage and retorting (excluded for in situ processing), oil upgrading and storage, and related parking, office, and shop facilities.

4/ Includes access roads, power and transmission facilities, water lines, natural gas and oil pipelines; actual requirements depend on site location. A 60-foot right-of-way for roads requires a surface area of about 8 acres per mile. Utility and pipeline corridors 20 feet in width require 2.4 acres per mile.

Source: Final Environmental Statement for the Prototype Oil Shale Leasing Program, U. S. Dept. of the Interior, August 1973, Vol. I, p. III-12.

Impacts would be significant in local areas but slight for the region as a whole because the percentage of the region's total surface area affected by development (including urbanization) would be small. However, the semi-remote character of the area would be modified and some local dislocations would unavoidably occur.

Impact on Water Quality

One of the greatest possible impacts would be the requirement of large amounts of water for retort plants and the disposal of waste water. Production of one million barrels per day of oil shale is expected to consume 121,000 to 189,000 acre-feet of water each year. 1/

In addition, as much as 10 gallons of water per ton of shale could be produced in the surface retorts. This water could contain dissolved saline and organic compounds. It could be used to moisten the waste shale to prevent dust problems. However, it would require treatment prior to other uses to remove hydrocarbons and malodorous compounds, and perhaps dissolved minerals.

Large quantities of natural ground water occur in leached zones of the deep oil shale areas, but the location, composition, and movement of such waters have yet to be defined in many areas. These aquifers may contribute substantially to the overall water supply available to satisfy requirements for oil shale development. Other sources are the Colorado River and its tributaries. To insure dependable supplies from these rivers might require construction of dams and reservoirs or purchase of water from existing reservoirs.

1/ Final Environmental Statement for the Prototype Oil Shale Leasing Program, U.S. Dept. of the Interior, August 1973, Volume 1, p. 111-57.

Use of ground water in oil shale development could decrease the natural discharge of springs and seeps. This could result in adverse effects on associated vegetation, and any fish or wildlife dependent on that water supply. Careful lease site selection to avoid natural water features which provide aquatic habitat and/or development of alternate water sources for wildlife would prevent or mitigate such effects.

Degradation of water quality could occur from discharge of product or waste waters, siltation of streams, or leaching of saline minerals from spent shale. It could be avoided in most cases by proper design, equipment, and adequate supervision and monitoring of operations. Leaching of spent shale would not be expected to be a problem because properly emplaced waste sites will harden through natural cementation.

In addition to these waters, there would possibly be a water slurry produced by a wet scrubbing process used to remove fine dust in gas streams. The slurry from the wet scrubbing could be used to wet the spent shale.

Water would also be used in the cooling phase of the process, but the amount needed could be kept to a minimum by employing air cooling. Any "sour" water streams produced by accidental contact with oil in final water condensers would be treated by conventional oil refinery methods.

The nature of the foreseeable problems associated with water quality would depend largely upon the mineral characteristics of the processed shale and the method of disposal. The foreseeable problems, as outlined, are believed controllable with present technology.

Impact on Air Quality

Techniques are being developed to adequately control emissions, including particulates, sulfur oxides, and nitrogen oxides potentially present in various fuel gases, and the dusts produced in mining and shale disposal. Residual concentrations of sulfur oxide, on the basis of a 200,000 bbl/day output, would total 12 to 40 tons per day depending on the process and nitrogen oxides would total 17 to 23 tons per day. Solid particulates in gaseous discharges to the atmosphere would be small, but unavoidable at the present state of technology. New control techniques now being developed for other industrial operations could be incorporated into this industry. Some local problems with temperature inversion may be experienced, the significance of which cannot now be established. The long term effect of industrialization would result in a decline in general air quality of the region.

The local noise level near developed sites is expected to increase, due to mining, retorting, and other processing operations. This is an unavoidable adverse consequence of increased industrial activity in a region which is presently predominantly a semi-wilderness, and can be only partially mitigated by noise abatement devices.

Impact on Fish and Wildlife

Construction and operation would have varying degrees of direct and indirect impacts upon fish and wildlife and their habitat in the immediate vicinity of the plants and along roads, surface facilities, and pipelines. Noise and associated human activities accompanying construction and operation would have a new effect of stress and disturbance on normal behavior and activity patterns of wildlife. Species which could be affected by such disturbances include mountain lion, bear, elk, mule deer, antelope, bob cats, sage grouse, blue grouse and migratory birds. Encroachment of humans causes loss of habitat, and often adjacent areas cannot support the displaced animals.

Air strips and increases in air traffic would provide some source of aerial harassment of mule deer, wild horses, and big game, the extent of which would be dependent upon the number and location of air strips and the volume of air traffic which would be involved.

Wildlife food and cover values of lands used for mining, pipeline and road construction, building, etc., would be at least temporarily lost. Permanence of such losses would be dependent upon the time required for and success of reestablishing useful wildlife food and cover. Such habitat loss would in turn result in lower populations of animals. For example, removal of critical winter browse would result in a corresponding reduction in mule deer numbers.

Oil shale-related drying of surface water features, such as springs,

seeps, and small streams, would change the natural plant-animal complex associated with each particular water feature, including the related distribution of game, wild horses and cattle.

Coverage of roadside vegetation with vehicle-caused dust would constitute a minor but chronic problem, since such vegetation would lose its wildlife food value until washed off by subsequent rains.

Unpredicted or uncontrollable changes in the quality of local surface or ground water would result in accompanying impacts on aquatic fish and wildlife populations and their habitat. In the event that sediment, leached substances, saline ground waters and/or toxic materials were released to surface waters as a result of oil shale operations, adverse impacts would be imparted to aquatic plant and animals. Unless carefully controlled, such discharges would have adverse effects on aquatic habitat of the Colorado, Green and White Rivers and other exposed water areas. Adverse impacts would also be expected in exposed aquatic habitat in the form of lowered biological productivity, and physical covering of fish spawning and nursery areas.

Handling, storage, and transmission, including feeder pipelines, would exhibit some small losses of oil. Spills would follow natural drainage features and released oil would kill trees, shrubs, and other vegetation with which it came into contact. Birds, some species of both land and water mammals, and fish and other aquatic organisms would be adversely affected if they came in contact with the oil.

Oil shale-related urbanization would also create stress on regional wildlife population. Reductions in surface water quality near population centers as a result of sewage, toxic substances and siltation, would adversely affect aquatic organisms and their habitat. Some wildlife habitat would be consumed by buildings, roads, parking lots, etc. Additional wind and water erosion would occur. Increased ground vehicle traffic would result in more frequent road kills of deer and other game.

Increased hunting pressure would cause localized adverse impacts upon wildlife through reduction of populations of some species, including a few already scarce species such as the brown bear and cougar. Increased harvest of mule deer, elk, moose and antelope would require regulation in order to avoid undesirable downward population trends. Both development and associated urbanization would aggravate conditions which cause some species to be classified as rare and endangered. Semi-remote hunting and fishing qualities would be lost.

RELATIONSHIP OF ALTERNATIVE TO PROPOSED OCS SALE

Under this alternative the expected oil and gas from the Texas OCS #34 sale would have to be replaced by 166,000 to 279,000 barrels a day of oil produced from oil shale. Since the oil shale industry in the U.S. is in its earliest stages, it is difficult to predict the magnitude of impacts associated with a given level of production. The Department of Interior, in its Draft Environmental Statement for the Proposed Prototype Oil Shale Leasing Program, estimated the impacts for the Green River Formation region.

Their estimates are based on a "unit tract" with a production level of 50,000 barrels daily for underground mines and 100,000 barrels daily for surface mines. Using these estimates, land requirement projections are given below for production of 300,000 barrels a day.

Surface Mining	Land required, acres
Mine development	90 to 255 yearly
Permanent Disposal, overburden	3,000 total
Temporary Storage, low grade shale	300 to 600 total
Permanent Disposal, processed shale	420 to 450 yearly
Surface facilities	600 total
Off-site requirements	540 to 1,800 total

Underground Mining

Mine development	60 total
Permanent disposal*	170 to 450 yearly
Surface facilities	840 total
Off-site requirements	1,080 to 1,350 total

*Upper estimate is for surface disposal of all processed shale.

Lower estimate is for underground return of 60% of processed shale.

The level of production needed to replace the proposed sale, 166,000 to 279,000 barrels daily, is considerably more than the projected development of the oil shale industry, which the National Petroleum Council estimates production to be 150,000 barrels a day by 1980 in the most optimistic case. The Interior Department has projected that oil shale production by this date could reach 400,000 bbls./day. Given the projected growth of oil shale capacity, it is unlikely that shale oil could replace the expected Texas OCS #34 sale oil and gas, at least not until the end of the present decade.

B. Synthetic Natural Gas and Oil

TECHNOLOGICAL PROCESSES

Through hydrogenation processes, it is possible to convert coal to various hydrocarbon liquid and gaseous substitutes for natural gas and oil. Considerable research and development has been done and continues in the Federal Government and private industry. While many individual units for commercial gas processes have been tested, synthetic gas has not yet been proved economical in the United States, and no commercial coal-to-liquid conversion plants exist in this country today. A typical coal-gasification process includes:

1. Pretreatment of coal (for sizing, drying)
2. Gasification
3. Char removal
4. Shift conversion to balance CO-H_2 (carbon monoxide and hydrogen) ratio for further reactions
5. Acid-gas removal and sulfur recovery
6. Methanation to convert CO and H_2 to CH_4
7. Drying

Different processes omit some of these steps and add others not listed. The gasification step is highly exothermic. The basic difference among processes is found in the ways in which this heat energy is supplied.

There are three types of systems for production of SNG:

1. Fixed bed units which require pretreatment of caking coals. The Lurgi process is the best example.
2. Fluid bed units which may or may not require pretreatment of caking coals. Some examples are the HYGAS process, the CO₂ acceptor process and the Synthane process.
3. Entrained bed units which do not require pretreatment of caking coals. An example is the BI-GAS process.

Figures IV-5 thru IV-11 show different coal gasification processes.

Carbon dioxide acceptor process

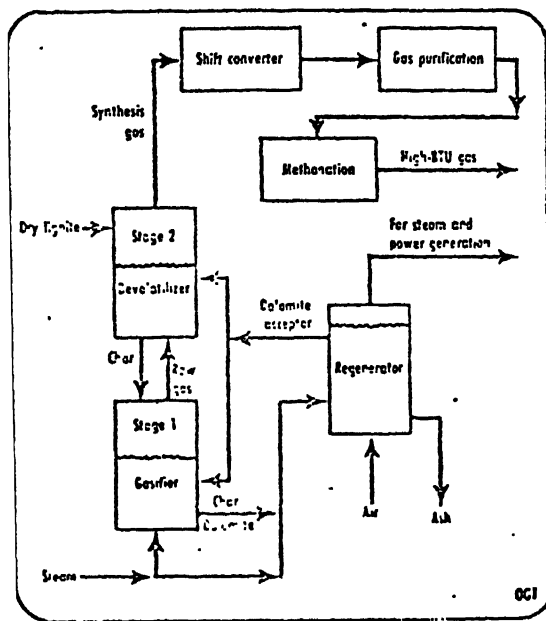


Figure IV-5

Bigas process

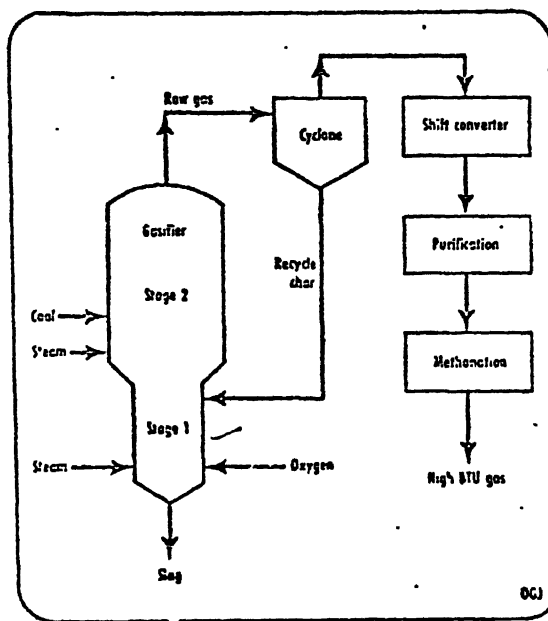


Figure IV-6

Source: D. C. Mehta and B. L. Crynes, "How Coal Gasification Commonbase Costs Compare," The Oil and Gas Journal (Feb. 5, 1973), pp. 68-70.

Figure IV-7

Hygas-electrothermal process

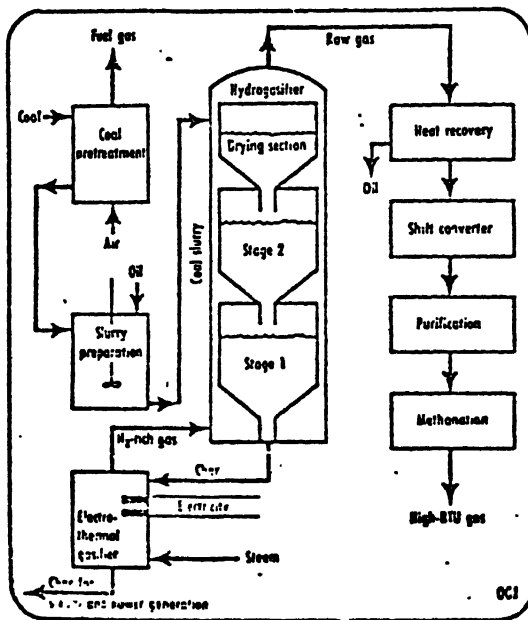


Figure IV-8

Lurgi process

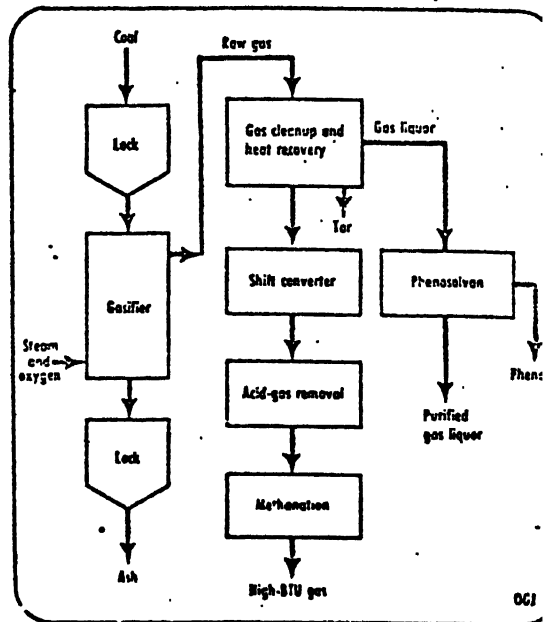


Figure IV-9

Molten-salt process

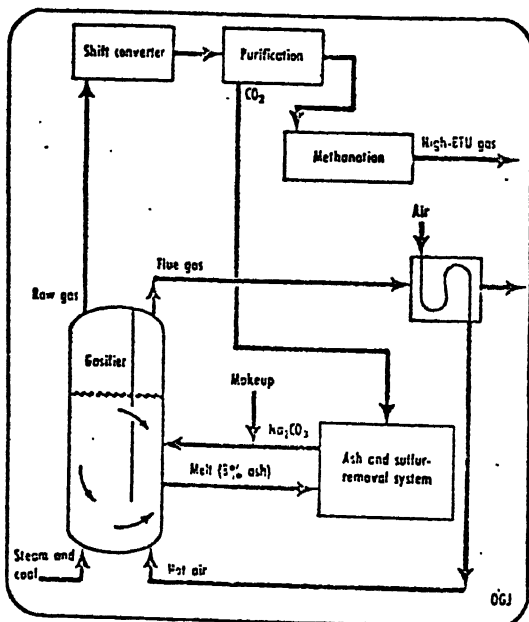
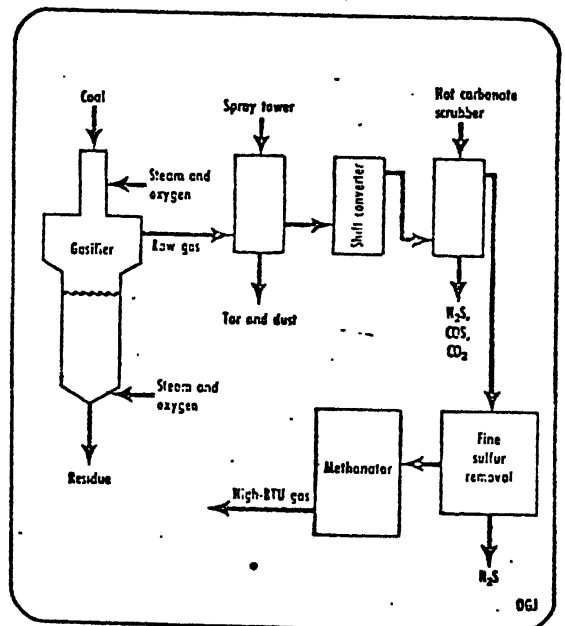


Figure IV-10

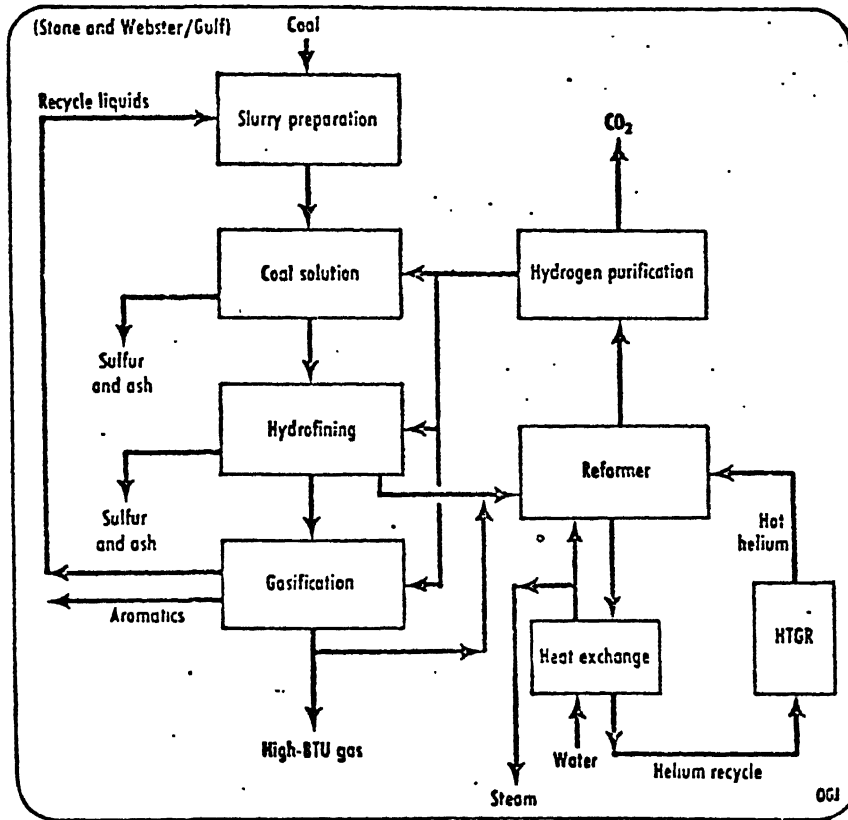
Synthane process



Source: D.C. Mehta and B. L. Crynes, "How Coal Gasification Commonbase Costs Compare," The Oil and Gas Journal (Feb. 5, 1973), pp. 68-70.

Figure IV-11

Coal-solution-gasification process



Source: D.C. Mehta and B. L. Crynes, "How Coal Gasification Commonbase Costs Compare," The Oil and Gas Journal (Feb. 5, 1973), pp. 68-70.

Coal Liquefaction

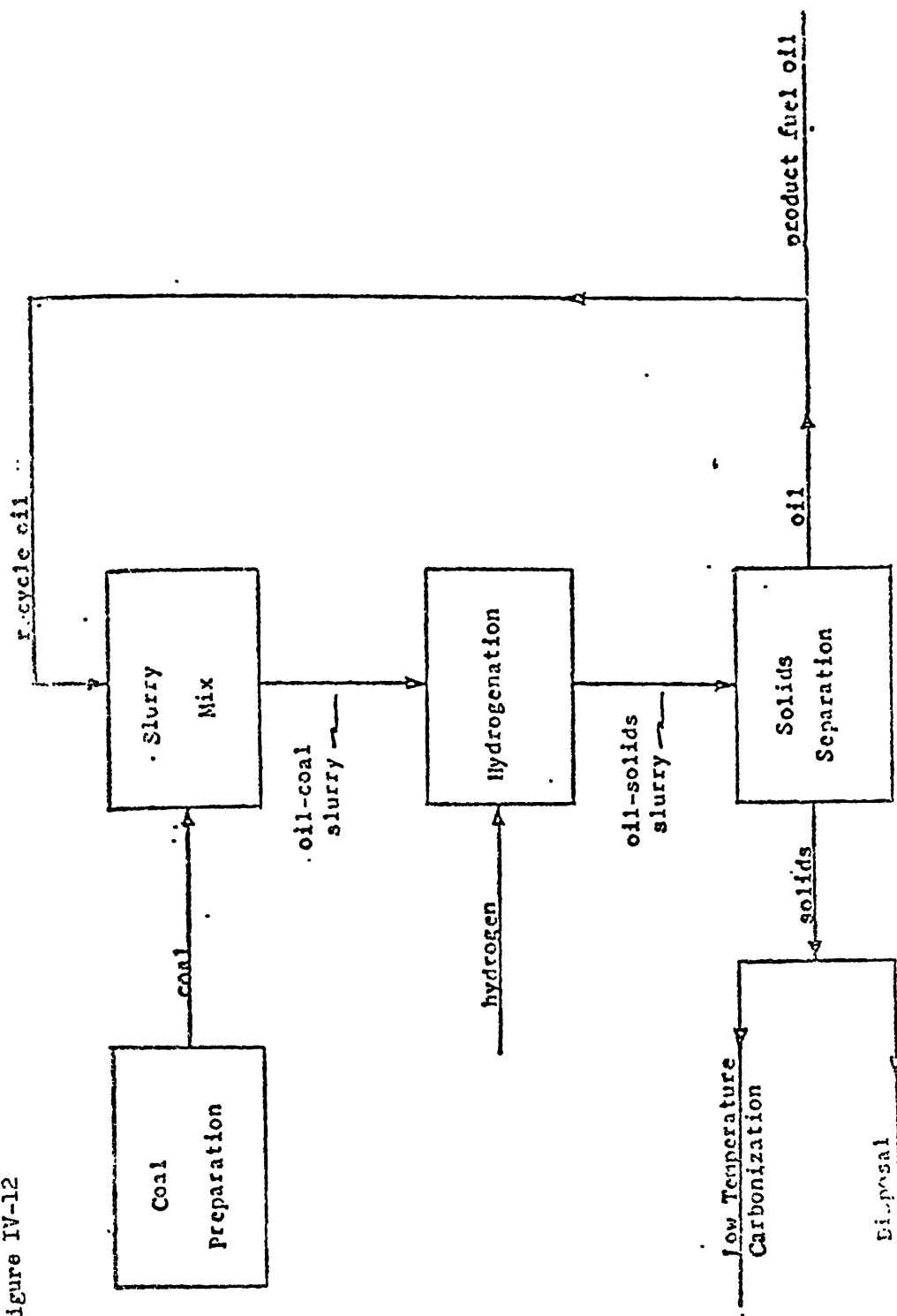
Until recently, there has not been the same sense of urgency with reference to the conversion of coal to clean-burning oil as exists for pipeline gas. One reason is that imported oil has been available at cheaper prices than a synthetic crude. Today coal liquefaction is receiving increased attention.

The Department of the Interior has filed a Final Environmental Statement, and will soon erect at Fort Lewis, Washington, a Solvent-Refined coal process (SRC) pilot plant. Consideration is now being given to the conversion of Project Gasoline and the pilot plant at Cresap, West Virginia, to test the consol synthetic fuels process (a simplified version of the H-Coal process), and a Bureau of Mines coal conversion process along with others. The plant will produce low-sulfur fuel oil from coal. The consol synthetic fuels process consists of two basic steps.

1. Extract production - The conversion of coal into extract and byproduct char and gas.
2. Extract hydrogenation - The conversion of coal extract into a hydrogenated low-sulfur fuel oil, a fraction of which is used as a solvent in extract production.

The Bureau of Mines Process, shown in Figure IV-12, is similar to the consol synthetic fuels Process.

Figure IV-12



Source: Draft Environmental Statement, Proposed Process and Equipment
 Revisions to the Synthetic Fuels Process Pilot Plant, Creesap,
 West Virginia - Office of Coal Research, Dept. of Interior,
 August, 1972.

BUREAU OF MINES PROCESS
 Low-Sulfur Fuel Oil

Natural gas can also be synthesized from petroleum. Such gas has been produced commercially in Europe and some 40 plants are in the planning stage for the United States. Feedstocks used range from naphtha and other lighter hydrocarbons to crude oil. While oil gasification does not add to overall energy supplies, it is one of the most promising short-term techniques of increasing gas supply with few environmental problems. Processes under consideration include:

1. Thermal cracking in steam.
2. Thermal cracking in a hydrogen-rich atmosphere.
3. Catalytic cracking in steam.
4. Partial oxidation.

Currently, much attention is being given to the catalytic rich process, developed by the British Gas Council. Called the CRG (Catalytic Rich Gas) process, it can gasify a wide variety of hydrocarbon feedstocks, though attention now is concentrated on naphtha feedstocks. The CRG process includes desulfurization of feedstocks, methanation and purification to a gas with a heating value of 998 btu per cubic foot.

Desulfurization of the feedstock is accomplished by mixing the feed with hydrogen-rich gas, vaporization, and treatment with nickel-molybdate and zinc oxide catalyst. If a high sulfur content feedstock is used, a hydrodesulfurization step could be employed.

RESOURCE BASE

The resource base and availability of coal and petroleum feedstocks is discussed in sections on each of these fossil-fuels. One 250 billion Btu per day coal gasification plant will require about six million tons of coal annually. Although coal resources are adequate for many years to come, the availability of large amounts of coal for gasification may be a constraint on the development of a gasification industry.

The availability of light hydrocarbons and refining capacity to produce feedstocks for SNG is questionable. About 20 to 25 thousand barrels of hydrocarbon feedstock will be required to produce 100 million cubic feet of SNG.

ECONOMIC CONSIDERATIONS

Coal gasification technology has not yet been fully developed and most processes have not advanced beyond the pilot plant stage. The CO₂ Acceptor process and HYGAS process are currently at pilot plant stage with partial operational tests on certain units. The Bigas and synthane processes are at pilot plant construction stage. The above three along with the Lurgi process are the most advanced in development among all coal gasification methods. The following table shows the status of various high Btu coal gasification processes and projects as of December 1972, with updates and information on new projects as of April 1973.

AS OF DECEMBER 1972

Coal

Name of Process	Owner(s) or Con-tractor and Site	Description of Process	Type	Status and Funding
Lurgi Pressure Gasifi-cation (Lurgi Gesell-schaft fur Warne und Chemo nik m.b.H.)	El Paso Natural Gas Co. (Four Corners Area, New Mexico)	A bed of crushed coal is intro-duced to the gasi-fer vessel through lock hoppers and travels downward as a moving bed. The process operates at pressures up to 450 psi. Steam and oxygen are intro-duced through a revolving grate which also removes ash at the bottom of the gasifier. The hydrogen-rich gas passes up through the coal bed, pro-ducting some methane by hydrogenation of coal. The product gas is purified and methanated to pro-duce 972 Btu/SCF gas.	Limited to non-caking coals	El Paso has made application to the FCC for authorization to construct and operate the Burnham Coal Gasification Complex on the Navajo Indian Reservation. Capital costs are \$33.2 million for the gasification plant and \$65.3 million for the associated mine. Initial gas pro-duction is scheduled for June 1976, and the estimated 1977 cost of gas at the plant outlet is \$1.20/MCF.
			Consumption, ton/day	
			26,600	
			Plant Output Million cf/day	
			250	

12) American Gas Association, Gas Supply Review 1: 3, December 15, 1972; 1:7, April 15, 1973

212

Name of Process	Owner(s) or Con-tractor and Site	Description of Process	Type of coal	Status and Funding
Lurgi Pressure Gasification	Texas Eastern Transmission Corp., Pacific Lighting Corp., Utah Inter-national, Inc. (Four Corners Area, New Mexico)	Same as above	Limited to non-caking coals	Feasibility study contract has been awarded to the Fluor Corp. Plant cost is estimated at over \$300 million. Plant operation could start in 1976.
Lurgi Pressure Gasification	Panhandle Eastern Pipe Line Co. and Peabody Coal Co. (Illinois)	Same as above	Limited to non-caking coals	Feasibility study contract has been awarded to M. W. Kellogg and American Lurgi Corp.
Lurgi Pressure Gasification	Conoco Methanation Co. and Scottish Btu product Gas from a Lurgi pressure gasifier to demonstrate the commercial feasi-bility of the com-bination of Lurgi methanation to produce a 950+ Btu/SCF gas.	Methanation of purified low-Btu product Gas from a Lurgi pressure gasifier to demonstrate the commercial feasi-bility of the com-bination of Lurgi methanation to produce a 950+ Btu/SCF gas.	subbituminous	Conoco Methanation Co. will design and construct facilities to carry out a 1-yr. test at a total cost of \$6 million. Eleven U.S. companies are sponsoring the test which is scheduled to begin in mid-1973. The con-struction contractor is Woodall-Duckham, Ltd.

Name of Process	Owner(s) or Con- tractor and Site	Description of Process	Type	Status and Funding
Lurgi Pressure Gasification	South African Coal, Oil, and Gas Corp., and Lurgi (Sasolburg, South Africa)	Methanation of the product gas from a Lurgi gasifier to produce 950+ Btu/SCF gas.	-	An experimental program to demonstrate commercial feasibility of methanation. A slip-stream from the SASOL plant will be used as feed to the methanator.
COCAS	COCAS Development Co. (FMC Corp., Panhandle Eastern Pipe Line Co., and Tenneco, Inc.) (Princeton, New Jersey)	Coal is charged to a series of fluidized-bed reactors with increasing stage tem- peratures to pyrolyze the coal and drive off volatile fractions in each stage. After separation of the oils and gas produced in the initial processing, the residual char is reacted with steam and air to produce a syn- thesis gas which is purified and methanated to a 950+ Btu/SCF gas. The operating pressure is 50 psig. The oil by-product is hydro- treated to make a synthetic crude oil.	subbituminous and bituminous	The first stage of the COCAS Process is based on results from the COED pilot plant in Princeton, N.J., which was designed to produce oil, char, and a relatively small amount of gas. The COED pilot plant was funded by OCR and completed in 1970 at a cost of \$4.5 million COCAS Development Company will invest an initial \$5 million for a pilot plant for an 18-24 month process evaluation.

212

Name of Process	Owner(s) or Con- tractor and Site	Description of Process	Type	Status and Funding
HYGAS	Institute of Gas Technology (Chicago, Illinois)	Ground, dried coal is preheated with air, slurried with by- product oil, and fed to a two-stage fluid- ized bed hydrogasifier operating at 1000-1500 psia; hydrogen-rich gas for the reaction can be furnished by processes using electric energy or oxygen, or by the steam-iron process. Gas from the reactor is purified and methanated to produce 950+ Btu/cu. ft. gas.	all U.S. coal types	Pilot plant in operation. Preliminary demonstration plant design complete. Original cost of pilot plant was approximately \$9.5 million.
Koppers-Totzek	Koppers Company	Raw coal is dried, ground and charged to a gasifier by a screw conveyor with a mixing head in which oxygen and steam are added to the coal fines. The reactor operates at atmospheric pressure and at 2700°F. The product gas, mostly hydrogen and carbon monoxide, can be methanated to produce 950+ Btu/SCF gas. Sixteen low-Btu plants are in operation in other countries, primarily to make synthetics gas for ammonia production.	all U.S. coal types	Process is being offered in U.S. and Canada under a general license from Heilnuch Koppers G.m.b.H., Essen, West Germany.

212

Name of Process	Owner(s) or Contractor and Site	Description of Process	Type	Status and Funding
ATGAS	Applied Technology Corp.	Coal is injected into a molten iron bath where steam and oxygen react with the carbon to produce hydrogen and carbon monoxide. The gases are then methanated to produce 950+ Btu/SCF gas.	all U.S. coal types	BVA has added \$222,000 to its July contract of \$620,000 for work on the high Btu gas process. A.C.A. has awarded the company \$282,000 for developing a pre-pilot plant to demonstrate the process.
Union Carbide	Chemical Construction Corp. (Chemico)	Coal is crushed and fed to a gasifier as a dry solid or water slurry. The coal is heated in the presence of steam by direct contact with hot ash agglomerates generated by the combustion process, producing a product containing carbon monoxide, hydrogen and about 10% methane.	-	A 15 yr. option on lignite reserves to convert to synthetic gas, not before 1980's.
Coteau Properties	(wholly owned subsidiary of North American Coal Corp) and Michigan Wisconsin Pipe Line Co.			

220

Name of Process	Owner(s) or Contractor and Site	Description of Process	Type	Status and Funding
Colorado Interstate Gas Co. and Westmoreland Resources	The Columbia Gas System, Inc.		-	A 10-yr. option on coal reserves. Feasibility of coal gasification plant will be studied.
Texas Gas "Trans-Mission Corp. and Consolidation Coal Co.			-	Core drilling program in West Virginia to identify possible sites for coal gasification facilities. 293 million tons of recoverable coal reserves have been proved on part of land on which the company has coal rights.
			-	Texas Gas Transmission Corp. has acquired one-half interest in a large block of Illinois Basin coal reserves controlled by Consolidation Coal Co. The largest parcel will be held for 10 years for possible use in a coal gasification project.

221

Name of Process	Owner(s) or Contractor and Site	Description of Process	Type	Status and Funding
None	Gulf General Atomic and Stone & Webster	Coal is dissolved and the solution is hydrocracked and reacted non-catalytically with hydrogen to produce gas which is purified and methanated to 950+ Btu/SCF gas.	all U.S. coal types	Feasibility studies being made.
None	Garrett Research and Development Co. (sponsored by Colorado Interstate Gas Co.)	Coal is introduced into a simple reactor at atmospheric pressure where gas is produced by rapid devolatilization of coal. Large amounts of excess char are produced.	all U.S. coal types	Early stage of development. Being tested in small pilot plant in La Verne, California.

Name of Process	Owner(s) or Contractor and Site	Description of Process	Type	Status and Funding
Kellogg Molten Salt Process	M.W. Kellogg Company	In the latest version of this process oxygen, steam and coal are injected into a high - purity alumina reaction vessel where molten sodium carbonate catalyzes the coal for complete gasification. The product gas can be purified and methanated to produce 950+ Btu/SCF gas.	all U.S. coal types	OCR funded a bench scale program from 1964-1967. Total expenditures were \$1.7 million. Major difficulties were experienced with materials of construction. OCR ceased sponsorship because of this problem, budgetary restrictions and assignment of higher priorities to other coal gasification processes. M. W. Kellogg has carried out additional development work since 1967, but support has not yet been obtained for construction of a large scale pilot plant.

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<u>Name of Process</u>	<u>Owner(s) or Contractor and Site</u>	<u>Description of Process</u>	<u>Type</u>	<u>Status and Funding</u>
(New Project)	Northern Natural Gas Co. and Cities Service Gas Co. (Powder River Basin, Montana)		Plant Output 250 million cf/day (initial plant)	Northern Natural and Cities Service are considering construction of four 250 million CF/day coal gasification plants. Peabody Coal has agreed to supply about 500 million tons of coal, and the gas companies are negotiating for another like amount. \$10 million will be spent for preliminary development through 1975. Construction of the first plant could start in 1976, with operation in 1979.
(New Project)	Natural Gas Pipeline Co. of America (Dunn County, N.D.)		Lignite	Rights to 2 billion tons of lignite have been obtained from Star Drilling Inc. The lignite will be reserved for possible future use in a coal gasification project.

The commercially available Lurgi coal gasification process is employed in several plants in West Germany and other parts of West Europe to produce low-Btu value gas (400-450 Btu/cf). Catalytic methanation, required to achieve pipeline quality gas of 1000 Btu/cf, has not yet been commercially demonstrated. The first commercial-scale test of production of pipeline coal gas will be undertaken by Conoco Methanation Company, which will add methanation facilities to the Scottish Gas Board's Westfield coal gasification plant by mid 1973. This plant uses the Lurgi process. The first commercial coal gasification plant to produce pipeline quality gas, will use the Lurgi process and will be built near Four Corners, New Mexico. The 250 million cubic feet per day plant, to cost about \$250 million, is expected to be in operation by 1976. The first operational Lurgi gasifier in the U.S. will be completed by El Paso Natural Gas Company in April 1974. The gasifier, also in the Four Corners area, will cost \$14.1 million and have no methanation step.

In August 1971, the Department of the Interior and the American Gas Association signed an agreement for an accelerated program for coal gasification which will cost about \$120 million over four years. Three pilot plants (HIGAS, BI Gas, and CO₂ Acceptor) will be in operation under the program. In each of the plants a unique gasification method will be tried in conjunction with different systems of gas cleanup and methanation so that a final process, combining the best features of the individual processes, can be chosen.

Part of the funds will go to the Applied Technology Corp. for development of the ATGAS process which uses a unique molten-iron gasification technique with steam and oxygen at low pressure. The product is a gas suitable for conversion to SNG. The process, which can gasify coal within a very large range of physical properties and sulfur content, enables economical use of coals for which there are few other markets. Construction and operation of a pilot plant is planned. Also under the program, Columbus Laboratories of the Battelle Memorial Institute is working on development of a coal-gasification fluidized-bed coal burner to provide the heat for steam gasification of coal. A pilot plant will be operated to obtain performance data for assessment of the commercial potential of the process.

An important part of the program is the development of the BI-GAS process (see Figure IV-6) to produce pipeline quality gas. The core of this process is the two-stage gasifier which uses pulverized coal in entrained flow. A pilot plant in Homer City, Pennsylvania is presently under construction and scheduled for start-up in 1974. Advantages of this process are 1) a high yield of methane obtained directly from coal, with minimal subsequent processing of the product gas, 2) no tars and oil are formed in the gasification process, 3) all the feed fuel is consumed in the process, and 4) the two-stage gasifier is relatively simple in design and amenable to scale-up to any size.

The economics of coal gasification will be greatly influenced by finalized process configurations. Intense interest has been shown by electric utilities in development of integrated coal gasification electricity generation systems using low Btu gas. Research also centers on processes whose major end product is pipeline quality gas with minor credits for by-products such as sulfur and phenol. Further advances may result in an optimized process which produces not only pipeline gas, but also liquid and solid hydrocarbon fuels and electric power.

Until further demonstration plant design and operation, estimates of capital requirements are speculative. In early 1972, FPC estimated that capital expenditures to develop gasification plants and supporting coal mines for supplying one trillion cubic feet of SNG annually for a period of 20 years would be \$2.4 billion. Capital expenditure for a 250 million cu. ft. per day gasification plant is estimated at about \$175 million. ^{1/} More recent estimates for this size coal gasification plant are from \$250 to \$300 million, which raise the capital expense of annual capacity of one trillion cubic feet to about \$3.0 to \$3.6 billion. The National Academy of Engineering, in a contract study for the Department of Interior, Office of Coal Research, estimated a \$3.4 billion capital investment for 12 coal gasification plants to produce one trillion cu. ft. of gas yearly.

^{1/} Federal Power Commission, Bureau of National Gas Supply and Demand, 1971-1990, staff Report No. 2, Washington, D.C., Feb. 1972, p. 90.

An evaluation of the economics of different coal gasification processes is shown in Tables IV-5 and IV-6. Costs are based on plant capacity of 250 million cu. ft. daily.

Capital requirements for SNG plants using petroleum feedstocks will be about \$800 million to \$1 billion. Prices for announced projects are from \$1.00 to \$1.60 per Mcf.

Table IV-5

Economics of processes, coal at 25¢/MMBTU

	CO ₂ acceptor			Bigas			Hygas-electrothermal			Molten salt			Lurgi		
	9%	12%	15%	9%	12%	15%	9%	12%	15%	9%	12%	15%	9%	12%	15%
Rate of return															
Total fixed investment, \$MM	103.31	103.31	103.31	170.00	170.00	170.00	156.12	156.12	156.12	159.60	159.60	159.60	286.00	286.00	286.00
Total working capital, \$MM	8.73	9.05	9.27	8.61	9.06	9.52	9.27	9.69	10.11	8.68	9.11	9.54	10.30	11.02	11.77
Total capital investment, \$MM	111.04	112.36	112.58	178.61	179.06	179.52	165.39	165.81	166.23	168.28	168.71	169.14	296.30	297.02	297.77
Net operating expenses per year, \$MM	49.84	49.84	49.84	56.16	56.16	56.16	58.70	58.70	58.70	53.46	53.46	53.46	69.40	69.40	69.40
Annual average revenue requirement, \$MM	57.34	60.71	63.23	67.46	72.71	77.97	69.20	74.06	79.02	64.12	69.06	74.04	87.72	96.23	104.87
20-year average gas selling price, ¢/MMBTU	69.4	73.5	76.5	82.4	88.9	95.4	83.4	89.3	95.3	81.1	87.4	93.6	109.1	119.6	130.4

Table IV-6

Economics of processes, coal at 35¢/MMBTU

	CO ₂ acceptor			Bigas			Hygas-electrothermal			Molten salt			Lurgi		
	9%	12%	15%	9%	12%	15%	9%	12%	15%	9%	12%	15%	9%	12%	15%
Rate of return															
Total fixed investment, \$MM	103.31	103.31	103.31	170.00	170.00	170.00	156.12	156.12	156.12	159.60	159.60	159.60	286.00	286.00	286.00
Total working capital, \$MM	11.36	11.68	12.00	10.81	11.28	11.77	11.79	12.47	12.84	10.74	11.19	11.64	12.33	13.07	13.82
Total capital investment, \$MM	114.67	114.99	115.31	180.81	181.28	181.77	167.91	168.59	168.96	170.34	170.79	171.24	298.33	299.07	299.82
Net operating expenses per year, \$MM	64.02	64.02	64.02	68.81	68.81	68.81	74.30	74.30	74.30	65.54	65.54	65.54	81.11	81.11	81.11
Annual average revenue requirement, \$MM	71.99	75.34	78.93	80.41	85.71	91.13	85.23	90.44	95.46	76.44	81.53	86.65	99.80	103.43	117.14
20-year average gas selling price, ¢/MMBTU	87.0	91.2	95.5	98.3	104.9	111.7	100.2	109.0	115.0	96.5	103.1	109.6	124.1	134.8	145.6

Source: D.C. Mehta and B.L. Crynes, "How Coal Gasification Commonbase Costs Compare", The Oil and Gas Journal, (February 1973), pp. 70-71.

The Department of the Interior 1/ gives the following forecasts for production of synthetic gas:

<u>Year</u>	<u>Total Gas Produced</u>		<u>Energy Inputs</u>	
	bil. cu. ft.	Tril. btu.	Coal mil. tons	Petroleum mil. bbl.
1980	700	700	19	84
1985	2,000	2,000	86	128
2000	5,500	5,500	308	105

Table IV-7

Factors that will influence the rate of growth of a coal gasification industry are the availability of coal and petroleum feedstocks, the development of needed mining capacity (including availability of manpower for mining), availability of capital, and availability of refining capacity to provide light hydrocarbon for feedstocks.

The National Petroleum Council has estimated SNG production from petroleum feedstocks at 0.6 trillion cf in 1975 and 1.3 tcf in 1980, and 1985. These figures reflect the assumptions that one third of announced plants will be operating by 1975 and one half of plants scheduled to be in production in 1980 and 1985 will be completed on schedule. These assumptions show the retarding effects of Government regulations, import restrictions, and siting and administrative delays.

1/ United States Energy Through the Year 2000, U.S. Department of the Interior, December 1972, p. 22.

ENVIRONMENTAL IMPACT

Like natural gas, the products of coal gasification or liquefaction (i.e., synthetic natural gas or coal oil) are clean-burning fuels as a result of the pollution control feature integral to the manufacturing process.

The first environmental obstacle common to all ventures using coal for energy is coal retrieval. In addition, coal gasification and liquefaction processes must contend with water consumption and contamination, air pollution from sulfur components and particulate matter, and possible noise and site pollution.

Impact on Air Quality

Plant operation, consisting of handling and transporting the coal to the process and converting the coal to gas or oil, will involve very large quantities of devolatilized coal, called char, which will be burned in boilers to generate process steam and power, or gasified to make process hydrogen. Major emissions that must be controlled are sulphur and nitrogen oxides, bottom ash and slag, and fly-ash from the plants generating process steam and power. Since coal-conversion plants are located next to strip mines, ash and slag from the process is returned to the open cuts, and the ground is restored in accordance with environmental considerations. The technology for controlling sulfur and nitrogen oxides from such plants is under development.

To illustrate the order of magnitude of the major emissions that would have to be handled from a commercial coal-to-pipeline gas plant, the FPC's National Gas Survey 1/ gave the following estimates, based on a plant producing 250 million standard cubic feet per day of pipeline gas 2/ from coal with 3.7 percent sulfur.

<u>Table IV-8</u>	<u>long tons per day</u>
Sulfur (mainly as hydrogen sulfide)	300-450
Ammonia	100-150
Phenols	10-70
Benzene	50-300
Oil and tars	tract to 400
Ash (based on coal with 10% ash)	1500

1/ Federal Power Commission, Final Report, Supply-Technical Advisory Task Force - Synthetic Gas - Coal, Chapter X, p. X-2. Prepared by the Synthetic Gas - Coal Task Force for the Supply - Technical Advisory Committee, National Gas Survey, May, 1973.

2/ This size SNG plant produces the equivalent of 40,000 barrels per day of crude petroleum.

The environmental impacts of SNG plants using naphtha feedstocks are expected to be less than those comparable coal-based synthesis plants, because they would be free of ash and char, and sulphur oxides and particulates discharge problems.

Impacts on Water Quality

Plant operation involves very large quantities of water for cooling and scrubbing gases, perhaps as high as 30 million gallons per day for a completely water cooled plant producing 250 million cubic feet of SNG per day. ^{1/} The discharge of contaminants such as phenols, cresols, benzene, oil, and tars must be controlled through use of purification systems integrated into the facility or through re-circulation of waste water to extinction. Process waste solids such as spent dolomite, in the case of the CO₂ Acceptor process, may present problems of surface water contamination.

Impact on Land Quality

Waste solids such as char, granulated extract, and powered sulfur must be disposed of. Much of the solid waste will be used as fill in trenches left by surface mining operations prior to recontouring of the land to match its original surroundings.

^{1/} Jane Stein, "Coal Is Cheap, Filthy, Needed", Smithsonian, Feb. 1972, p. 25. A water requirement of 8 to 9 million gallons daily for a partially air-cooled plant is given in Coal Age, mid-April 1973, "Challenges and Opportunities of Western Coal", p. 42.

RELATIONSHIP OF ALTERNATIVE TO PROPOSED OCS SALE

This alternative would involve a combination of synthetic oil and gas with a total value of 0.96 to 1.62 trillion Btu's, the energy equivalent of the oil and gas expected from the proposed Texas OCS #34 sale. The mix could range from all synthetic oil, 166,000 to 279,000 barrels a day, to all synthetic gas, 0.93 to 1.57 billion cf a day.

Complete substitution by coal gasification would require 4 to 7 250 billion Btu's per day coal gasification plants, 19 to 41 million tons of coal per year, and 7 to 14 coal mines. At an estimated \$250 million for each plant, these plants would cost \$1.0 to \$1.75 billion.

Projections of the Interior Department for the development of the coal gasification industry estimate yearly production of coal gas by 1980 at 700 billion cf. To completely replace the expected Texas OCS #34 sale oil and gas production would call for 0.34 to 0.57 trillion cubic feet a year of coal gas. This quantity could be produced if the projected 1980 production is an accurate prediction. In view of the present lack of a commercial coal gas industry and the uncertainty of the related economics and technology, the possibility of coal gas serving as an alternative to the projected sale is doubtful. About 122 to 151 thousand barrels of hydrocarbon feedstocks would be required each year to produce 0.57 tcf of gas.

5. Hydroelectric Power

TECHNOLOGICAL PROCESSES

Conventional hydroelectric developments convert the energy of natural regulated streamflows falling through heads ^{1/} created by dams and waterways to produce electric power. Plants are classified as run-of-river or storage projects, depending on the way in which available streamflow is utilized. In conventional plants, water comes to the plant as a result of natural means.

Pumped storage projects generate electric power by releasing water from an upper to a lower storage pool and then pumping the water back to the upper pool for repeated use. During off-peak hours when project capacity is not required by the system, water is pumped to the upper pool using energy generated by other sources, usually by large modern steam-electric units. A pumped storage project consumes more energy than it generates. Its economic advantage comes from converting low-cost, low-value off-peak energy to high-value peak capacity and energy, and from the highly flexible peaking power it makes available. Pumped storage projects may be designed exclusively as pumped storage or may be included in the design of a conventional hydroelectric installation.

^{1/} Head refers to the height of fall for use in calculating water pressure per unit area.

RESOURCE BASE

The total conventional hydroelectric power potential of the 48 contiguous states at both developed and undeveloped sites is estimated to be about 146,000 MW of capacity able to produce about 530 million megawatt hours of electric energy annually. Of this total, 94,000 megawatts and 272 million megawatt hours remained undeveloped as of January, 1972. Although most available sites for economical production of hydroelectric energy have been developed, some additional capacity will be provided by new sites or expansion of existing plants. Use of hydroelectric power to service peak loads enhances project benefits, permitting consideration of possibilities which formerly were marginal or uneconomic under higher capacity factor standards. Multipurpose benefits such as recreation, water supply, fish and wildlife enhancement, and flood control justify projects that would otherwise be uneconomic for a single purpose.

The availability of pumped storage sites largely depends on topography which allows development of a high head between two reservoirs in the same area. In many parts of the country, there are virtually unlimited physical opportunities for developing pumped storage projects. However, only a limited number of sites have been investigated.

ECONOMIC CONSIDERATIONS

The investment in hydroelectric projects per kilowatt of installed capacity varies greatly according to the type of project, size and location, the cost of lands required, and the cost of relocation of highways, buildings, railroads, and other improvements. The capital costs of powerhouse and equipment per unit of installed capacity decreases with an increase in head. The unit cost at a particular site is less if large capacity units are installed rather than more units of smaller size.

Excluding pumped storage, average investment costs per kilowatt are substantially higher for hydroelectric plants than for thermal-electric plants. Capital costs of hydroelectric plants range from \$200 to \$400 per kilowatt of installed capacity. Total capital costs of conventional plants built in the 60's ranged from about \$40 million for capacity of about 200MW to \$200 million for capacity of about 700MW. On the other hand, operating expenses are much lower, largely because no fuel is required and other operating and maintenance costs are less.

Pumped storage plants have low capital costs ranging from \$100 to \$150 per kilowatt installed, and low maintenance costs. Total capital costs are from \$30 million and up.

Present and Projected Supply-Demand

The Department of the Interior 1/ gives the following projection for hydropower development that includes both hydro and pumped storage plants.

Table V-1

Present and Projected Hydropower and Total Electric Utility Capacity

Installed Capacity (MW)			Net Generation (billion KW hrs)		
<u>Year</u>	<u>Total Electric Utility</u>	<u>Hydropower</u>	<u>Hydropower as a % of total electric utility capacity</u>	<u>Total Electric Utility</u>	<u>Hydropower</u>
1971	367,395	55,898	15.2%	1,614	266
1975	480,000	80,000	16.7	2,130	350
1980	660,000	95,000	14.4	3,000	420
1985	915,000	120,000	13.1	4,140	470
2000	1,880,000	200,000	10.6	9,010	700

The Federal Power Commission projects conventional electric generating capacity in the contiguous United States as follows:

1/ United States Energy Through the Year 2000, U.S. Department of the Interior, December 1972, p. 26.

Table V-2

Conventional Hydropower, Pumped Storage, and Total
Electric Generating Capacity by Region

<u>Year</u>		<u>Total electric generating capacity</u>	<u>conventional hydro capacity</u>	<u>pumped storage capacity</u>
1970	Northeast	64.9	5.8	1.8
	East Central	55.0	1.0	0.1
	Southeast	63.7	9.3	0.1
	West Central	42.6	3.5	0.4
	South Central	48.9	2.3	0.1
	West	64.9	29.7	0.1
	Total contiguous U.S.	340.0	51.6	3.6
1980	Northeast	113	7	9
	East Central	103	2	4
	Southeast	132	11	4
	West Central	82	3	2
	South Central	106	3	3
	West	129	42	5
	Total contiguous U.S.	665	68	27
1990	Northeast	201	7	19
	East Central	186	3	14
	Southeast	255	13	13
	West Central	152	3	4
	South Central	211	4	8
	West	255	52	12
		1,260	82	70

Source: 1970 National Power Survey, Federal Power Commission, December 1971, I-8-28-9. All units are thousands of megawatts.

The predomination of pumped storage over conventional hydropower in new construction can be seen in the percentage below, calculated from the above table.

Year	conventional hydro as percent of total electrical generating capacity	pumped storage as percent of total electrical generating capacity
1970	15.2	1.1
1980	10.0	4.1
1990	6.5	5.6

ENVIRONMENTAL IMPACT

Impact on Air Quality

Construction activity increases the dust in the air. However, operation of the hydroelectric power plant produces no air pollution, radioactivity, nor waste heat.

Impact on Water Quality

Construction often results in temporary increases in stream turbidity. The newly filled reservoir usually has a low dissolved oxygen content. Reservoirs concentrate salt due to evaporation.

Impact on Land Quality

Construction of a hydroelectric dam represents an irretrievable commitment of the land resources beneath the dam and lake. Inundation of the land eliminates wildlife habitat and precludes other uses such as agriculture, mining, and free-flowing river recreation. Some increase in erosion during construction and operation will occur.

Impact on Fish and Wildlife

Fish and wildlife habitat may be significantly changed. The reproductive habitats of anadromous fish may be severely altered by dam construction, unless elaborate provision is made for fish ladders or other means to provide safe fish passage. Significant mortalities of resident and anadromous fish in rivers servicing hydroelectric dams can be caused by gas-bubble disease resulting from exposure to nitrogen supersaturated water. Nitrogen supersaturation results at a dam when excess river flow must be passed over the spillway.

Survival studies conducted in 1971 indicate that high nitrogen levels in the Columbia and Snake Rivers pose a serious threat to the future of the salmon and steelhead resources of the region. 1/ Under present plans to expand the Columbia Basin hydroelectric system through 1980, the volume of spills at the various projects will be reduced. However, without additional control measures, the reduction in volume of spills will not be great enough to reduce nitrogen supersaturation to levels considered safe for fish during years of average or higher flows.

1/ Power Planning Committee, Pacific Northwest River Basins Commission, Review of Power Planning in the Pacific Northwest, Calendar Year 1971, pp. 71-76, submitted by Idaho State Director, Bureau of Land Management.

The Corps of Engineers is actively engaged in studying and testing several approaches to the solution of the nitrogen problem. Efforts have been concentrated on manipulation of storage, full use of generating units, slotting intake gates, collection and transportation of downstream migrants, and spillway modifications.

RELATIONSHIP OF ALTERNATIVES TO PROPOSED OCS SALE

The hydroelectric generating capacity required to substitute for the energy from the oil and gas expected from the proposed Texas OCS #34 sale depends on whether the oil and gas is employed in direct end uses (such as oil and gas heating) or in electricity generation. Since direct uses convert oil and gas to energy more efficiently, a larger generating capacity would be required to substitute for this energy.

To substitute for end uses of the Texas OCS #34 sale oil and gas, capacity of 10 to 17 thousand megawatts would be needed. To substitute for the electricity which could be generated by the oil and gas, 5 to 9 thousand megawatts of capacity would be needed.

The extent of U.S. conventional hydropower potential east of the Mountain states, the region to be served by the proposed Texas OCS #34 sale, is shown below.

Region	Potential Power	Developed Capacity	Undeveloped Capacity
New England	4.8	1.5	3.3
Middle Atlantic	8.6	4.3	4.3
East North Central	2.2	0.9	1.3
East South Central	9.1	5.2	3.9
West North Central	7.0	2.7	4.3
South Atlantic	14.5	5.5	9.0
West South Central	5.1	2.1	3.0
Total	51.3	22.2	29.1

All units are thousands of megawatts.

Source: From "Hydroelectric Power Resources of the United States, Developed Undeveloped, January 1, 1973," Federal Power Commission, December, 1972.

The feasibility of hydropower as an alternative to the oil and gas expected from the Texas OCS #34 sale is restricted by other factors. Hydroelectric power can not be substituted for use of oil and gas in transportation and in industrial processes dependent on unique properties of oil and gas. Land use considerations may preclude development of the few promising potential conventional hydro sites east of the Mountain states. Sites where pumped storage projects may be developed are numerous but have not been systematically inventoried. Furthermore, few dams are built solely for hydroelectric power generation. Irrigation, navigation, municipal and industrial uses, and flood control are frequently more important than and not fully compatible with power production needs. Since hydropower is most often used to service peak loads, other energy sources must be relied on for base power loads.

6. Nuclear Power

TECHNOLOGICAL PROCESSES

One of the most important advances in the electric power industry in the past few decades has been the development of nuclear energy. Nuclear reactors fall under two types: "thermal" or "fast". Thermal reactors, including the light-water reactors, employ moderating materials to slow the neutrons before the majority of fissioning occurs; in fast reactors fission is produced by neutrons of much higher energy levels. The fast reactor offers the possibility of using a much greater portion (estimated 60 percent) of the potential energy in the uranium ores.

The predominant nuclear system utilized in the U.S. currently is the uranium dioxide fueled, light-water moderated and cooled nuclear power plant. This cycle accounts for most of the electric power generated by nuclear fuels in the U.S. today, and is expected to predominate through most of the next decade. In the light-water reactor, the heat energy created in nuclear fission is removed by the circulation of water through the fuel core. The heated water produces steam which turns turbine generators. The water thus functions both as a coolant to transport the heat released in fission and as a moderator to slow down the fast neutrons produced in fission. Fuel is in the form of slightly enriched uranium dioxide pellets encased in tubing of a zirconium alloy. The fuel rods are assembled into bundles. Control rods are strategically placed in the fuel to control the rate of the nuclear reaction.

The light-water reactor supporting fuel cycle includes the following components.

1. Mining uranium ore.
2. Processing the ore to produce uranium concentrates.
3. Production of uranium hexafluoride from uranium concentrates to provide feed for isotopic enrichment.
4. Isotopic enrichment of uranium hexafluoride to attain reactor enrichment requirements using the gaseous diffusion process.
5. Fabrication of nuclear reactor fuel including converting uranium hexafluoride to uranium dioxide, pelletizing, encapsulating in rods and assembling fuel elements.
6. Production of power from the reactor.
7. Reprocessing irradiated fuel to recover plutonium produced and unburned uranium and converting the uranium to uranium hexafluoride for recycle through the gaseous diffusion plant for reenrichment.
8. Radioactive waste management of high level and other wastes, including long-term storage of wastes.
9. Transportation of materials to and from each of the above operations.

RESOURCE BASE

AEC develops estimates of two types of uranium resources. "Reserves" refers to known deposits that can be economically produced at a given market price. "Potential resources" refers to additional uranium that may exist in unexplored extensions of known deposits or in undiscovered deposits within or near known uranium areas. These estimates do not represent the total uranium resources of the U.S.

as other uranium areas undoubtedly exist and will be discovered in the future. However, discovery of new deposits outside known mining areas in the long term may become increasingly difficult and expensive since the chance of discovery falls markedly in less known areas.

Each resources category is also qualified by market price. Estimates at lower prices are more precise because they are based on better data from industry exploration, which has focused on lower price reserves.

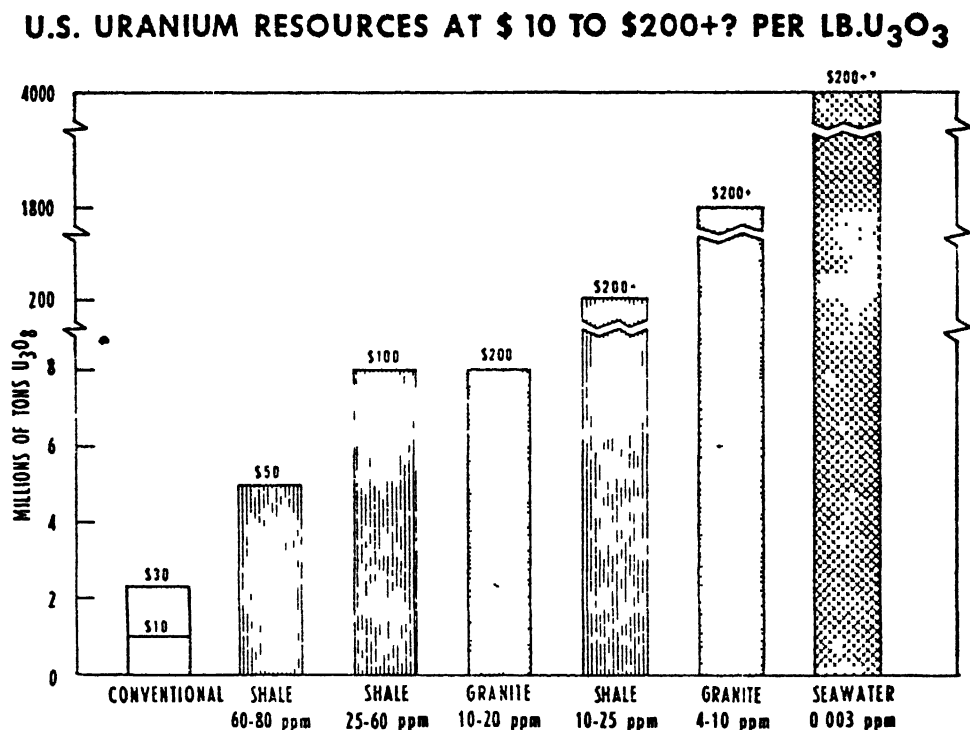
Of reserves of U_3O_8 at \$8 a pound, about 50% is found in New Mexico, 35% in Wyoming, 6% in Texas, 3% in Colorado, and 3% in Utah. The remainder is scattered throughout the Western United States. As of the beginning of 1973, AEC estimates that \$10 reserves of U_3O_8 in conventional deposits in the western U.S. (including \$8 per pound U_3O_8 reserves) were 337,000 tons. Potential resources of U_3O_8 in the Western U.S. were an additional 450,000 tons at \$8 and 700,000 tons at \$10. In 1972, approximately 41% of U_3O_8 production came from New Mexico, 33% from Wyoming, 7% from Colorado, and 6% from Utah.

ECONOMIC CONSIDERATIONS

Adequacy of uranium reserves depends on the resource base and time frame being considered. A large gap between long term uranium requirements and resources is shown if resources are confined to the \$8 per pound U_3O_8 reserves. This gap narrows progressively with the inclusion of \$8 per pound potential resources, \$10 per pound reserves, \$10 per pound potential resources, and so on. If shorter term demand is considered, reserves at \$8 per pound are about equal to the next 10 to 11 years requirements.

The first figure below shows U.S. uranium resources at different prices. The second shows uranium production, reserves, and potential. 1/ These figures may be compared to AEC estimated requirements from 1972 through 2000 of 2,400 tons U_3O_8 , or about 10 times total past production in the U.S. to date.

Figure VI-1



1/ Atomic Energy Commission, Division of Production and Materials Management, Nuclear Fuel Resources and Requirements, April 1973, pp. 16, 22.

PRODUCTION TO DATE, RESERVES, AND POTENTIAL COMPARED TO REQUIREMENTS

Tons U_3O_8

	<u>1948-1972 Production</u>	<u>Cutoff Cost</u>	<u>Reserves</u>	<u>Potential</u>	<u>Total</u>
Ambrosia Lake	67,000	\$ 8 \$15	54,000 97,000	30,000 59,000	151,000 223,000
Other New Mexico	30,000	\$ 8 \$15	80,000 148,000	189,000 395,000	299,000 573,000
Wyoming	47,000	\$ 8 \$15	98,000 190,000	90,000 265,000	235,000 502,000
Other U. S.	100,000	\$ 8 \$15	41,000 85,000	141,000 281,000	282,000 466,000
Total U. S. A.	244,000	\$ 8 \$15	273,000 520,000	450,000 1,000,000	967,000 1,764,000

Requirement Estimate 1972-2000 -- 2,400,000

OR

16 Ambrosia Lakes

10 Times Total U. S. Production to Date

Although uranium at prices up to \$15 per pound may be economically competitive in water reactors in the future, the effort to develop the capability to produce such low-grade ore will not begin until there are indications of a market at that price. The uranium content of \$15 resources ranges from 0.10-0.12% U_3O_8 compared to 0.20-0.22 for \$8 resources. Therefore, almost twice as much ore must be processed to produce an equivalent amount of uranium. Depending on the characteristics of lower grade deposits, much more than twice as much material may be displaced. Thus, industry materials handling capacity would have to at least double.

Capital costs of nuclear power plants have increased in the past few years. The AEC has developed a method to estimate costs for a specific power plant on the basis of a reference case cost. A detailed cost model is selected and modified using data input for the specific project, such as plant type and location, beginning and start-up dates and rate of interest during construction. The model case may be broken down into over a hundred cost accounts, each of which can be adjusted separately. This procedure was used to develop the following estimates for the base capital cost of a 1000 Mwe pressurized water reactor reaching commercial operation in 1980.

Table VI-2
Capital Estimates for a 1000 Mwe
Pressurized Water Reactor for Operation in 1980
(\$ million)

1. Land	1
2. Structures and site facilities	38
3. Reactor/boiler plant equipment	59
4. Turbine plant equipment	68
5. Electric plant equipment	16
6. Miscellaneous plant equipment	5
7. TOTAL DIRECT COST	187
8. Contingency allowance	12
9. Spare parts allowance	1
10. Indirect costs	49
11. TOTAL MID-1972 COST	249
12. Escalation to start of construction*	—
13. TOTAL AT START OF CONSTRUCTION	249
14. Interest during construction	63
15. Escalation during construction*	99
16. TOTAL AT COMMERCIAL OPERATION	411
17. Allowance for cooling towers	20
18. Allowance for near zero radwaste system	4
19. Allowance for SO ₂ removal system	—
20. TOTAL COST AT COMMERCIAL OPERATION IN 1980	435

*Escalation rates are 5%/year for equipment and materials and 10%/year for site labor.

Source: Capital cost calculations for Future Power Plants, compiled from AEC source material and summarized by F.C. Olds, Senior Editor, Power Engineering, January 1973.

Installed nuclear capacity is currently ²⁵,000 MW. The AEC projects 1/ capacity will increase to 52,000-57,000 MW by 1975, 127,000-144,000 MW by 1980, and 256,000-332,000 by 1985. The most likely estimates are 132,000 MW in 1980, 280,000 MW in 1985, and 1,200,000 MW by the year 2000.

ENVIRONMENTAL IMPACT

Impacts on Air Quality

Nuclear power plants, unlike fossil fuel plants, do not emit the usual products of combustion such as particulates, sulphur oxides, and nitrogen oxides. Hence, air pollution problems from such emissions do not occur. However, they do produce radioactive emissions whose release must be strictly limited if adverse affects to the health of humans and other biota are to be avoided.

In the normal operation of nuclear generating units, there are small amounts of radionuclides discharged in the cooling water and gaseous plant effluents. Assuming that present standards will be maintained and enforced (these limit the release of radioactivity to no more than would expose an individual at the plant boundary to 1% of the individual maximums allowed), the effects of the amounts released are likely to be negligible, as the average additional annual dose which the affected population would receive, would be three to four orders of magnitude less than the average level of natural radiation exposure.

1/ Wash-1139(72) Nuclear Power 1973-2000, Dec. 1, 1972.

Impact on Water Quality

Operation of the light water reactor plants will generate considerable amounts of waste heat due to their comparatively lower thermal efficiency (around 33% compared to 40% for new coal-fired fossil-fueled thermal plants). Given this difference in efficiency and on the assumption that fossil fuel plants release around 15% 1/ of their waste heat directly into the atmosphere, a light-water reactor would release approximately 50% 2/ more waste heat into its cooling water than a fossil fuel plant of similar size. The effects of this waste heat will depend upon the cooling method used and the location of the plant.

The use of cooling ponds would produce less forced evaporation than wet cooling towers, but haze, fog, cloud, and ice formation would still occur during periods of sub-freezing temperatures.

Assuming a 15-20 degrees F temperature rise, a "once through" method of direct discharge into the original source for a 1,000 MW plant would require 270-360 billion gallons of water per year. The effects of using a "once through" method of cooling heated water depend in part on the size of the body of water into which this heated water is discharged. The effects along ocean sites, the Great Lakes, and

1/ Energy Research Needs, Oct. 1971, Sec. IX, Resources for the Future, pg. 19.

2/ Ibid, Section VI, pg. 15.

very large rivers are likely to be modest as the heat is more readily dispersed and more easily avoidable by aquatic species. Along smaller lakes and rivers or in bays with limited circulation, the effects can be more significant. Within the affected areas, higher water temperature may produce fish kills, interfere with fish reproduction, disrupt food chains, decrease dissolved oxygen content, drive out desirable aquatic species and encourage the growth of undesirable algae which may speedup eutrophication. However, sometimes the heat can be used for aquaculture and other beneficial uses.

Impact on Land Quality

Most uranium mining takes place in relatively isolated semi-desert areas distant from large population centers. The removal of vegetative cover and the creation of overburden and waste rock result from uranium mining. Of the \$8 ore reserves as of January 1, 1973, 55% will require underground mines. Open-pit mining disturbs a 4-5 hundred acres over 1000 MW reactor lifetime, reducing suitability of the area for other uses such as grazing wildlife and some types of outdoor recreation. In underground mining, the extraction of ores requires some accumulation of waste rock in dump areas but causes much less disturbance than open-pit mining. Careful planning for sequential land use, including reclamation of mined land and the backfilling of mined-out stopes and pits with mined material, can substantially reduce land use problems.

Because of low concentration of U_3O_8 in uranium ore, most of the ore milled ends up as low level radioactive tailings that must be retained in well constructed tailings dams to prevent erosion and leaching. Tailings are not a suitable environment for future habitation and are unsuitable for use as fill material in construction where human occupancy is involved. To minimize erosion from above ground storage, the tailings can be covered with gravel or dirt. Above ground storage of tailings requires about 60 acres of land for a reactor lifetime and displaces other uses.

Under current siting criteria, nuclear plants would be located at some distance from population centers. Assuming 500 acres per site (based upon an exclusion area of one-half mile radius around each plant), and an average of three 1,000 MW units per site, the construction of 3,000 MW of additional nuclear capacity would thus require 500 acres from which other uses would be excluded. Cooling ponds require additional acreage (an estimated 1,000-2,000 acres per 1,000 MW unit).

Depending on the capacity of the transmission lines needed, the transmission line rights-of-way would require the use of ten to fifteen acres per mile of line. Certain types of development, such as residences, would be excluded although such land would still be largely available for other purposes, such as recreation. Additional

transmission lines for electricity are required regardless of how the electricity is produced, whether by nuclear plants, hydropower, or fossil fuels.

Plant construction would present short-run environmental problems such as the erosion of excavated materials and subsequent siltation.

Control of Radioactive Emissions

Risk of Accidents

The operation of nuclear plants poses some risk of accidents. Nuclear plants are designed to minimize accidents or their adverse effects if one does occur, utilizing a "defense-in-depth" principle. This includes siting reactors in remote areas, designing and constructing plants to prevent accidents and to contain the effects of accidents were they to occur. Plants are designed to withstand a design basis accident, defined as the worst malfunction considered to have a probability of occurrence high enough to warrant corrective action. For light-water reactors, the worst design basis accident considered is usually a major rupture in the primary cooling system.

The maximum radiation dose which could be received at the site boundary if such an accident were to occur is estimated for most plants not to exceed the annual dose obtained from natural radioactivity.

Transportation

The nuclear fuel cycle requires the transportation of radioactive materials by truck or rail at several stages. The transportation of spent fuel elements from reactors to processing plants and high-level waste from reprocessing plants to storage sites poses a potential hazard of considerable magnitude. Transportation regulations and cask designs have been developed to insure that even if accidents in transporting these materials do occur, no radioactivity will be released to the environment.

Fuel Reprocessing

Spent fuel assemblies from reactors are first partially cooled at the plant site and then transported to fuel reprocessing plants where useable nuclear fuel materials are recovered from them and radioactive wastes are separated. At present there is one such fuel reprocessing plant and two more are under construction. Each reprocessing plant can serve 30 to 50 nuclear plants. While radioactive emissions during fuel reprocessing are greater than those occurring during normal power generation, the estimated dose to the affected population is still two orders of magnitude below natural levels. Hence, the impact of these emissions is not expected to be significant, even though the chronic effects of such level radioactivity are not yet wholly known.

Radioactive Waste Storage

High-level radioactive wastes remaining after reprocessing are first concentrated and stored in solution for five years, then solidified, sealed in containers, and put into long-term storage. An incremental capacity of 1,000 MW would produce around 8,000 to 10,500 gallons of high-level waste per year, using a cumulative storage capacity of 40,000 to 54,000 gallons. This liquid waste, when evaporated, would yield around 80 to 105 cubic feet/year in solid waste materials for each year of operation.

Because of their high concentrations of radioactive nuclides and very slow rates of decay, these waste materials must be isolated from the biosphere for hundreds of thousands of years if adverse effects to living organisms are to be totally avoided. Waste is presently being stored in below the surface man-made engineered storage facilities. Research is being conducted to find a permanent storage repository. As part of this research pilot studies of storage in salt beds are being conducted.

Relationship of Alternative to Proposed OCS Sale

We have calculated the nuclear capacity required to generate electricity to substitute for OCS sale production for two cases:

- (1) all of the OCS oil and gas were used to generate electricity, and
- (2) all of the OCS oil and gas were devoted directly to end uses such as oil and gas heating.

Nuclear capacity required to substitute for the electricity which could be generated by the projected oil and gas from sale No. 34 would be 5 to 9 1000 MW plants.

Capacity required to substitute for end uses would be 10 to 17 1000 MW plants. Associated parameters are shown for both cases, assuming model 1000 MW light water reactors.

	5 to 9 1000 MW light water reactors	10 to 17 1000 MW light water reactors
a. tons U_3O_8 first core fuels-first year only <u>1/</u>	2800-5040	5600-9520
b. thousands of tons of uranium ore required for a. <u>2/</u>	1400-2520	28-476

1/ Assuming 70% plant factor.

2/ Assuming 0.20% average ore grade.

	5 to 9 1000 MW light water reactors	10 to 17 1000 MW light water reactors
c. tons U_3O_8 yearly annual reloads without plutonium recycling 1/	875-1575	1750-2975
d. thousands of tons of uranium ore required for c. 2/	438-788	875-1487
e. tons U_3O_8 yearly annual reload ³ with plutonium recycling 1/	600-1080	1200-2040
f. thousands of tons of uranium ore required for e. 2/	300-540	600-1020
g. acres of land required for sites 3/	8500-15,000	16,500-28,500
h. thousands of gallons of high level radio- active wastes pro- duced yearly.	45 -81	90-153

1/ Assuming 70% plant factor.

2/ Assuming 0.20% average ore grade.

3/ Assuming an average of 1,500 acres per 1000 MW unit for cooling ponds and 500 acres per site containing three 1000 MW units.

7. Energy Imports

a. Oil Imports

PROJECTIONS OF FUTURE IMPORT LEVELS

Based upon the analysis presented in section I, oil imports will play an important role in fulfilling the United States demand for petroleum. Using figures presented in that section, the following table shows the expected demand for petroleum, the expected domestic production and supplemental supplies that will be required to fulfill demand. If domestic production is not stimulated and/or if the domestic demand is not reduced, supplemental supplies through 1980 will come in the form of increased imports. For the purposes of analysis in this section, the assumption is made that necessary foreign supplies will be available. It is not yet clear, however, what level of export Arab states will allow after the boycott, which began in October 1973, is lifted.

Table VII-1
Total U.S. Petroleum Demand Domestic Production and
Supplemental Supplies Through 2000
(million barrels/day)

	1971	1975	1980	1985	2000
Total Petroleum Demand	15.1	17.4	20.9	25.0	35.6
Total Domestic Production	11.3	11.0	11.8	11.6	10.6
Supplemental Supplies	3.8	6.4	9.1	13.4	25.0

Source: "U.S. Energy Through the Year 2000", U.S. Department of the Interior, December 1972, p. 43.

The National Petroleum Council's analysis of the energy situation provides some other projections of imports through 1985. 1/ For their analysis, the NPC developed four different cases based upon varying economic conditions and oil and gas finding rates. Case I represents the best of all conditions, while Case IV represents the worst and Cases II and III are intermediary conditions. The following table presents NPC's projections of imports that will be needed to balance demand.

Table VII-2

Projected Level of Oil Imports (NPC)
(millions of barrels/day)

<u>Case</u>	<u>1975</u>	<u>1980</u>	<u>1985</u>
I	7.2	5.8	3.6
II	7.4	7.5	8.7
III	8.5	10.6	13.5
IV ,	9.7	16.4	19.2

1/ National Petroleum Council, U.S. Energy Outlook, December 1972.

Another way of viewing oil imports is to examine their relationship to total petroleum supply. Figure VII-1 shows the percentage of the total U.S. petroleum supply made up by imports. The solid line from 1971 represents projections made by the Interior Department while the broken lines represent projections by NPC. This graph demonstrates the increasing importance of imports which is caused by rising demand and stationary domestic production.

PRESENT OIL IMPORT POLICIES

Until President Nixon's energy message of April 18, 1973, imports of crude oil, unfinished oil, and oil products were limited under the Mandatory Oil Import Program established in 1959 by Presidential Proclamation 3279. In his message, the President stated that "the Mandatory Oil Import Program was established at a time when we could produce more oil at home than we were using. . . Today, however, we are not producing as much oil as we are using, and we must import ever larger amounts to meet our needs. As a result, the current Mandatory Oil Import Program is of virtually no benefit any longer." For this reason the President adopted a program whereby controls and tariffs upon imports of crude oil, unfinished oils, and finished petroleum products were lifted; such imports were made subject to a gradually increasing scale of license fees; and the levels of fee-exempt imports were gradually reduced. However,

Figure VII - 1

Petroleum Imports
as Percent
of
Total Petroleum Consumption

Percent of Total Consumption

100
90
80
70
60
50
40
30
20
10

1950 1955 1960 1965 1970 1975 1980 1985 1990

Actual Projected

NPC IV

NPC III

Interior

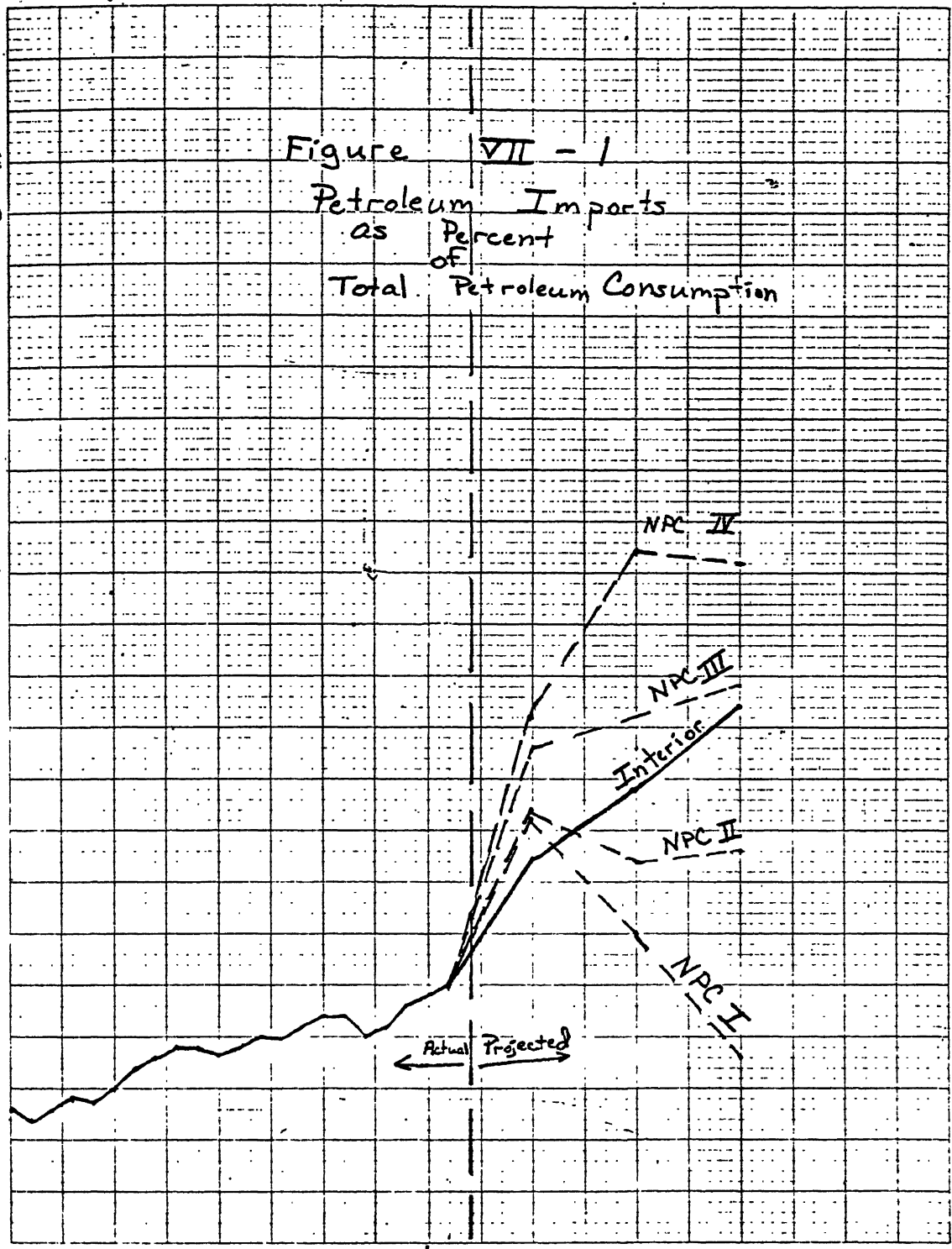
NPC II

NPC I

F45

Year

267



fee-exempt imports, designed to encourage the construction of expanded domestic refinery and petrochemical capacity and to encourage exports of petrochemicals, will continue to be available.

Under the quota system, the level of petroleum imports were restricted on the basis of product (commodity), geographical area in the United States and, in some instances, country of origin. Petrochemical firms and oil refiners applied to the Director of the Interior Department's Office of Oil and Gas (OOG) for allocations of crude oil, unfinished oils, or finished products and for import licenses. The Director of the OOG then determined by an established procedure the quantity of each which could be imported into Petroleum Administration for Defense Districts I through IV (see Figure VII-2), District V and Puerto Rico and issued import licenses accordingly. These allocations were made on a one year basis. Table VII-3 shows the import allocations for 1973.

Figure VII-2

Petroleum Administration for Defense (PAD) Districts

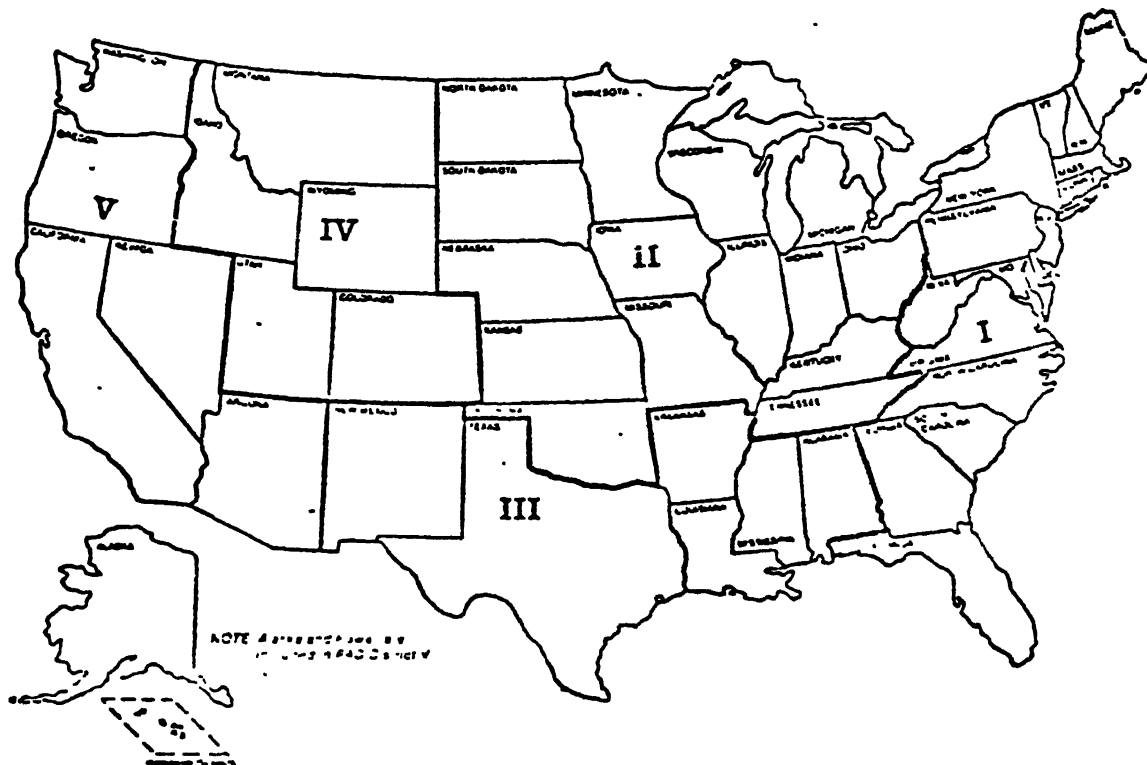


Table VII-3
 Import Allocations (thousands barrels/day)
 PAD Districts I-IV

	<u>1973</u>
Crude and Unfinished Oils	2,886.0
Finished Products (excluding residual fuel oil)	133.0
Residual Fuel Oil	2,900.0

District V

Crude and Unfinished Oil	942.5
Finished Products (excluding residual fuel oil)	7.5
Residual Fuel Oil	75.6

Through April 30, 1974, under the new program importers will not be required to pay a fee on their previously allocated import levels. The amount of duty-free imports which will be permitted will be reduced each year until reaching zero in 1980. In 1974, 90 percent of the initial allocation will be exempt from the license fee; in 1975, 85 percent; in 1976, 65 percent; in 1977, 50 percent; in 1978, 35 percent; in 1979, 20 percent; and in 1980, zero. 1/

The license fees will also change over time. The following table shows the schedule for fee increases for crude oil, for residual fuel oil, unfinished oils and refined products other than gasoline, and for gasoline.

1/ "New Import Program Sets Up 'Fees'", The Oil Daily, April 19, 1973, p. 1.

Table VII-4
Projected Fee Schedule 1/
(¢ barrel)

Date	Crude Oil	Residual Fuel oil and refined products other than gasoline	Gasoline
May 1, 1973	10.5¢	15.0¢	52.0¢
Nov. 1, 1973	13.0	20.0	54.5
May 1, 1974	15.5	30.0	57.0
Nov. 1, 1974	18.0	42.0	59.5
May 1, 1974	21.0	52.0	63.0
Nov. 1, 1975	21.0	63.0	63.0

The Office of Oil and Gas will continue to administer the oil import program. A license to import will be granted upon application to that office. The Oil Policy Committee, under the Deputy Secretary of the Treasury, will be responsible for policy decisions related to oil imports. The license fees will be reassessed from time to time to be sure that the goals of stimulating domestic production and increasing refinery capacity are being met.

1/ "New Import Program Sets Up 'Fees'", The Oil Daily, April 19, 1973, p. 4.

IMPORT FLOW PATTERN

Sources of Imports

In the past, the United States has received most of its imports from Western Hemisphere sources. Because of declining resource availability and increasing domestic demand, it does not seem likely that these countries will be able to meet the future U.S. need for imports. Table VII-5 shows estimates made by the NPC of Western Hemisphere liquid hydrocarbon supply-consumption balances. The estimates are based on their Case III supply estimates. In 1960 the Western Hemisphere was able to essentially maintain a balance in the supply and consumption of petroleum. This balance was almost achieved again in 1965.

The availability of Latin American oil was a major factor in reaching these balances. In the future, however, the increases in Latin American consumption are expected to be greater than increases in production. This factor combined with the great increases in United States consumption will cause larger and larger deficits in the Western Hemisphere petroleum supply-demand balance.

Table VII-5

WESTERN HEMISPHERE LIQUID HYDROCARBON SUPPLY-DEMAND BALANCE (1960-1985)*
(MMBBL/DAY)

	1960	1965	1970	1975	1980	1985	
						Low	High
Local Oil Consumption (Excluding Exports)							
United States	9.8	11.5	14.7	18.3	22.3	25.8	
Canada	0.9	1.1	1.5	1.9	2.3	2.7	3.0
Latin America	1.7	2.1	2.8	3.9	5.1	6.5	7.0
Total Western Hemisphere	12.4	14.7	19.0	24.1	29.7	35.0	35.8
Conventional Liquid Hydrocarbon Production							
United States	8.0	9.0	11.3	9.8	11.6	11.8	
Canada	0.5	0.9	1.5	2.2	3.0	3.7	
Latin America	3.8	4.7	5.3	5.8	6.7	7.0	
Total Western Hemisphere	12.3	14.6	18.1	17.8	21.3	22.5	
Synthetic Liquid Production							
United States	—	—	—	—	0.1	0.5	
Canada	—	—	—	—	0.4	1.0	
Latin America	—	—	—	—	0.3	0.8	
Total Western Hemisphere	—	—	—	—	0.8	2.3	
Total Liquid Hydrocarbon Pro- duction (Conventional Plus Synthetic) Available for Net Export or (Imports Required)							
United States	(1.8)	(2.5)	(3.4)	(8.5)	(10.6)	(13.5)	(13.5)
Canada	(0.3)	(0.2)	—	0.4	1.1	2.0	1.7
Latin America	2.1	2.6	2.5	1.9	1.9	1.3	0.8
Total Western Hemisphere	—	(0.1)	(0.9)	(6.2)	(7.6)	(10.2)	(11.0)

* All estimates are on a CAFE 10 supply basis.

Source: U.S. Energy Outlook, p. 241.

Future increases in oil imports will come primarily from the Middle East and North Africa. It has been estimated that almost 80 per-cent of the non-communist world oil reserves lie in these two areas. 1/

Problems with the security of supply, balance of payments, and United States off loading terminal capacity could arise due to an increase in imports from this region. Some of these problems will be examined later in this section. Using the Department of Interior projections of import levels the following table shows the breakdown of oil imports by source.

Table VII-6
Imports by Source
(million barrels/day)

	1975	1980	1985 <u>2/</u>	
			Low	High
Western Hemisphere	2.3	3.0	3.3	2.5
<u>Eastern Hemisphere</u>	<u>4.1</u>	<u>6.1</u>	<u>10.1</u>	<u>10.9</u>
Total Imports	6.4	9.1	13.4	13.4

1/ U.S. Department of Commerce, Maritime Administration, Offshore Terminal System Concepts, Vol. I, Figure No. 1-13.

2/ Low and High values refer to the expected Western Hemisphere oil consumption in the previous table.

Destination of Imports

The bulk of oil imports in the past have entered PAD District I. This district has a high demand for oil caused by a concentration of population and industry and very limited oil production. Figures in Table VII-7, which presents 1970-PAD District supply-demand balances, show that 71.5 percent of 1970 imports entered this district. Table VII-8 which shows 1985 PAD District supply and demand balances based on NPC's Case III, indicates that PAD District I will continue to have large deficits. In 1985, District I will require shipments of about 10 million barrels/day. Even if all surplus domestic production were shipped to District I, which seems unlikely given the projected deficit in District II, there would still need to be about 7.4 million barrels/day of foreign oil brought into the East Coast.

Table VII-7 - 1972 Supply Distribution and Sources
(Thousand barrels per day)

District	Production Crude oil & NGL	Domestic Receipts		Imports	
		Crude and NGL	Refined Products	Crude and NGL	Refined Products
District I	88	284 (II) 24 (III) 257 (IV) 3 (V) --	2,996 (II) 61 (III) 2,932 (IV) -- (V) 3	971 Canada 113 Other West. Item. 243 Europe 402 Africa Middle East 213	2. Canada Other West. Item. 1. Europe Africa Middle East Other E. Item.
District II	1,275	1,812 (I) -- (III) 1,552 (IV) 260	759 141 594 24	513 Canada 492 Other West. 2 Item. Africa 13 Middle East 6	Canada Other West. Item. Europe
District III	7,943	21 (I) 9 (II) 5 (IV) 7 (V) --	73 73 --	77 Other West. Item. 21 Europe 1 Africa 53 Middle East 2. Canada 70	Other West. Item. Europe Africa Middle East Canada
District IV	677	-- (III) 2 (IV) 35	53 (III) 27 (V) 26 145	70 Canada 70	Canada
District V	1,193	37 (III) 2 (IV) 35	64 (III) 64 (IV) 81	671 Canada 266 Other West. Item. 33 Africa 1 Middle East Middle East Other E. Item. 205 Other E. Item. 166	Canada Other West. Item. Middle East Other E. Item.

Sources:
Bureau of Mines
Mineral Supply
March 26, 1973

Table VII-8
1985 U.S. Petroleum Liquids
Production 1/ and Demand - NPC Case III
(Thousands of barrels/day)

<u>PAD District</u>	<u>Production</u>	<u>Demand</u>	<u>Surplus (Deficit)</u>
I	201	10,211	(10,010)
II	906	6,859	(5,899)
III	6,458	4,332	2,126
IV	952	697	255
V	3,742 <u>2/</u>	3,688	54
Total United States	12,313	25,787	(13,474)

Source: NPC, p. 276.

In 1970, PAD District II had a large oil deficit which was filled primarily by shipments from District III and imports from Canada. In 1985, if all projected oil surpluses from other districts and all projected Canadian imports (Table 5) were sent to District II, about 1.5 million barrels/day would still be required to achieve a balance in that area.

1/ Includes synthetics.

2/ Includes Alaska.

Increasing oceanborne imports into District II would require an expansion of logistical systems in the upper Midwest and Mid-continent areas. There would have to be construction of new petroleum pipelines and/or additional barge traffic on the Mississippi River system. Significant volumes of imports will undoubtedly enter the Gulf Coast region because a transportation network currently exists which carries oil from the Gulf to the Midwest. It is unlikely, however, that this system could handle the projected increases.

The 1985 surpluses for PAD District V are based on the availability of Alaskan North Slope oil. If the Trans-Alaskan pipeline is built, the West Coast should not need significant quantities of petroleum imports. After that time, however, increased demand will probably have to be met with imports. 1/

TANKER AND TERMINAL REQUIREMENTS

In 1971, total tanker arrivals for the lower 48 States were 67,770. Of these arrivals 56,700(84%) were in PAD District I; 6,650 were in PAD District III (10%); and 4,420 were in PAD District V (6%). Many of the shipments were of products from the Gulf Coast and the

1/ NPC, op.cit., p. 275.

Caribbean to PAD District I. The average size of tankers carrying imported crude was 29,000 DWT. 1/ To deliver 1971 imports of 3.0 million barrels/day would have required the unloading of the equivalent of 15, 29,000 DWT tankers each day. In 1985, when waterborne imports are projected to rise to 10.7 million barrels/day 2/, 53 tankers of that size would have to be unloaded each day. This increase in throughput and ship traffic can only be met through some type of expansion of United States port capacity.

One of the key factors that will determine the changes that will be required in U.S. port facilities is the size of tankers delivering the oil. Since 1965, tanker construction has been directed almost exclusively toward vessels larger than 65,000 DWT. The development of a successful single unit point mooring system which allows the unloading of deep draught tankers, and the closing of the Suez Canal in mid-1967, gave impetus to the construction of Very Large Crude Carriers (VLCC's) ranging from 250,000 DWT to 425,000 DWT (presently under construction). A tanker of more than 700,000 DWT

1/ Fact Sheet Attachment to President Nixon's Energy Message, April 18, 1973. (DWT=dead weight ton, the cargo carrying capacity in long tons, 2240 lbs).

2/ NPC., op.cit., p. 181.

has been ordered and a 1,000,000 DWT vessel is in the preliminary planning stage. Figure VII-8 shows the growth of the world tanker fleet by size of vessel from 1960-1971.

The major attraction of large tankers is the reduction in unit transportation costs that they provide. Table VII-9 shows the cost in dollars per ton for the major routes bringing oil to the United States. The Venezuelan route averages about 4,000 nautical miles to the East Coast, the North African route about 8,000 nautical miles and the Persian Gulf route about 24,000 miles. The savings that are possible using larger ships over longer distances are apparent. While a 250,000 DWT tanker would save \$0.50/ton over a 65,000 DWT tanker on the Venezuelan route, it would save \$2.50/ton on the Persian Gulf route. With the shift of primary source of imports from Latin America to the Middle East, this savings will be important for the United States. ^{1/}

^{1/} In 1971, waterborne oil imports were 149 million tons; in 1980 they are projected to be 533 million tons.

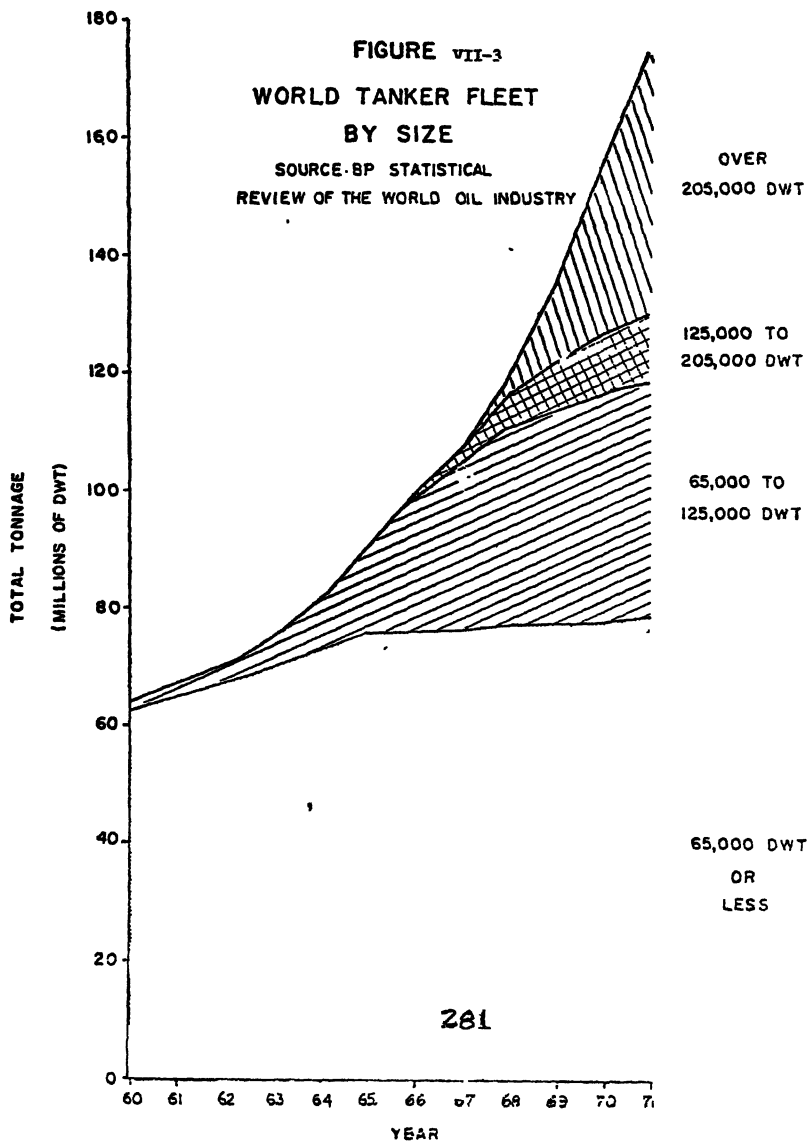


Table VII-9
Freight Cost of Transporting Oil
(\$/ton)

Ship size in DWT	Round-trip Distances in Nautical Miles		
	4000 <u>1/</u>	8000 <u>2/</u>	24,000 <u>3/</u>
65,000	\$1.90	\$3.50	\$9.05
250,000	1.40	2.50	6.55
326,000	1.25	2.30	6.15
500,000	1.00	1.90	5.45

Source: U.S. Department of Commerce, op.cit. Vol. I, Figure 1-32.

The possible reduction in ship traffic is also obvious if larger tankers are used. By using tankers of 100,000 DWT instead of 29,000 DWT, the number of vessels that would have to unloaded each day could be reduced from the equivalent of 53 to the equivalent of 15. By using a 200,000 DWT average, the number of unloading required each day could be reduced to the equivalent of 7.5.

1/ Venezuelan Route.

2/ North African Route.

3/ Persian Gulf Route.

Because of the savings in transportation costs, the reduction in ship traffic and the lack of new small tankers, it seems inevitable that the United States will be forced to use tankers larger than 100,000 DWT. The problem is that, as shown in Table VII-10 the U.S. does not have any ports capable of handling tankers larger than 100,000 DWT. The East Coast, which requires the greatest amount of imported petroleum, has only one port capable of handling a tanker larger than 55,000 DWT. The study done for the Department of Commerce's Maritime Commission shows that it is neither environmentally nor economically feasible and in some cases physically not possible to dredge existing ports to the depth necessary to allow large tankers to enter.

Several potential alternatives for importing the increased quantities of petroleum were examined in the Maritime Administration study. Some of these are: 1) lighten the loads of the VLCC's, offshore of existing ports, thereby reducing the drafts of the vessels sufficiently to allow them to enter the ports and complete the unloading. (This procedure is presently being used to a limited extent in Delaware Bay and New York); 2) develop a fleet of shallow-draft large tankers which could use the present, or moderately deepened, port channels; 3) make use of conventional designs such as building a deep-draft terminal in Maine or in Lower Delaware Bay, or using single point mooring systems offshore; 4) transfer the oil to the U.S. in small tankers from deep-water terminals

Table VII-10

U.S. TANKER PORTS*

Port	Maximum Vessel Size (DWT)	Port	Maximum Vessel Size (DWT)
Alaska-Nisiki	60,000	Massachusetts-Boston	50,000
California-Long Beach	100,000	New Jersey-Newark	25,000
California-Los Angeles	100,000	New York	55,000
California-Port San Louis Oospo	20,000	Pennsylvania-Philadelphia	55,000
California-San Diego	35,000	Texas-Baytown	30,000
California-San Francisco	35,000	Texas-Beaumont	80,000
Florida-Jacksonville	30,000	Texas-Brownsville	35,000
Florida-Miami	20,000	Texas-Corpus Christi	50,000
Florida-Port Everglades	35,000	Texas-Freepor	30,000
Hawaii-Honolulu	35,000	Texas-Houston	55,000
Louisiana-Baton Rouge	45,000	Texas-Port Arthnr	55,000
Louisiana-New Orleans	45,000	Texas-Texas City	45,000
Maine-Portland	80,000	Virginia-Hampton Roads	50,000
Maryland-Baltimore	55,000	Washington-Seattle	45,000

* George Weber, ed., *International Petroleum Encyclopedia* (1972), p. 407.

Source: NPC, op.cit., p. 282

being built in Canada and the Bahamas; and 5) make use of offshore deepwater ports, serving an entire region by a transfer system of pipelines and/or feeder vessels. 1/

The two promising of these alternatives are the use of conventional design for deep-draft terminals or single point mooring systems and

1/ U.S. Department of Commerce, op.cit., Executive Summary, p. 16.

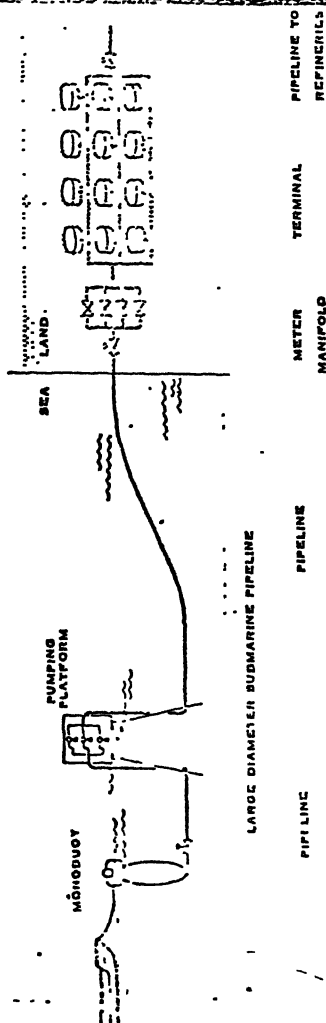
the use of a deep-water port terminal. Offshore lightering and transferring at a foreign port would add an extra cost, thereby reducing the benefits of lower shipping cost offered by larger tankers. Transferring the petroleum from large to small vessels in the Bahamas or Canada would continue the use of a number of small tankers and would, therefore, do little to relieve port congestion. At the present time, it does not appear to be economically practical to build ships of the required capacity with drafts sufficiently shallow to enter U.S. ports. 1/

Two types of facilities are possible for importing large amounts of oil. The first is the construction of conventional type facilities. The petroleum industry has proposed the construction of deep-water terminals in the vicinity of Machiasport, Maine, and at Big Stone Beach in Lower Delaware Bay. These proposals have not yet been implemented due to a variety of economic and environmental problems. Another method of increasing importance are Single Point Mooring (SPM) systems; which are presently used in over 100 locations around the world. The SPM's can be used as loading and unloading facilities for crude oil and petroleum products (Figure VII-4). The oil is transferred from the tanker to the buoy through floating hoses. When not in use, these hoses are normally allowed to swing freely on the water surface; however, newly designed hoses are able to sink to the bottom when out of use to reduce damage from adverse wave conditions

1/ U.S. Department of Commerce, op.cit. Executive Summary, p. 16.

conditions and ship maneuvering. The hoses are connected to a swivel on the buoy which allows them to rotate through 360 degrees. The oil is transferred through the buoy to a submarine pipeline by flexible hoses which allow free movement of the buoy in response to wave and tidal action. The oil is then piped to onshore storage facilities. SPM's are usually located far enough offshore and in deep enough water to obviate the need for dredging; however, if the location of the buoy should be too far from onshore storage/utilization facilities, it may be necessary to provide auxiliary pumping capacity mounted on a fixed platform near the buoy.

The second type of facility is a self-contained deep-water port. These offshore terminals would contain loading and unloading facilities, as well as storage tanks, pumping equipment and other necessary support equipment (Figure VII-5). These ports may be either platform type structure supported by pilings or artificial islands. These can handle petroleum products as well as dry bulk commodities; however, the size and complexity means greater costs than an SPM. The terminals usually consist of an unloading/loading platform which is connected to the main platform or island. Designs to date normally show a breakwater to provide protection for the terminal. Transshipment from a deep-water complex to mainland storage, processing, or distribution facilities can be made by smaller shuttle vessels, tugbarge systems, pipelines, or trestle-conveyor systems or some combination of these.



FLOW CHART OF A SINGLE POINT MOORING SYSTEM
 (from: "Seadock, A Proposal for a Texas Offshore
 Oil Unloading Facility")

Figure VII-4

Table VII-11 shows the number of VLCC arrivals and the number of berths required for the projected level of imports. In the table one berth represents unloading facilities for one tanker. While one SPM buoy represents one berth. One deep-water port, could contain several berths. The average VLCC size is based on the assumption that the trend toward larger tankers will continue.

Table VII-11
Average VLCC Size, Arrivals and
Berth Requirements

Year	Average VLCC Size (DWT)	Arrivals/Day	Deep Water Berths Required
1980	200,000	5.0	13
1985	250,000	5.6	15
2000	325,000	7.6	20

REFINERY REQUIREMENTS

As of January 1, 1973, U.S. domestic refinery capacity (operating and operable shutdown) was 13.7 million barrels/day. The following table shows the breakdown of this capacity by PAD District. Actual crude runs in 1972 were 11.7 million barrels/day. 1/

<u>PAD DISTRICT</u>	<u>CAPACITY (MILLION BARRELS/DAY)</u>
I	1.6
II	3.8
III	5.6
IV	0.5
V	2.2

1/ NPC, p. 280.

In analyzing future refinery requirements, a maximum case can be identified. The maximum case would be to meet demand for petroleum products with supplies run through U.S. refineries. All imports would, therefore, be crude oil. Crude runs in 1980 would be about 20.9 million barrels/day, and in 1985, 25.0 million barrels/day. This would mean an increase in crude runs of 9.2 million barrels/day by 1980 and 13.3 million barrels/day by 1985 over the actual 1970 levels.

The maximum refinery requirement would be to provide just enough capacity to process domestic production. In this case all imports would be in the form of petroleum products and petrochemical and SNG feedstocks. Crude runs would be 11.8 million barrels/day in 1980 and 11.6 million barrels/day in 1985. Both of these figures are less than 1973 total capacity, but about equal to actual crude runs in 1970. The retirement of old and obsolete facilities would require the construction of some new capacity through 1985. 1/

Recognizing that, for economic and security reasons, the United States should not rely on petroleum products imports, President Nixon created incentives for the expansion and construction of refineries to process foreign crude. Under the new import system, companies building new refineries or petrochemical plants, or

1/ NPC, p. 280.

expanding present facilities, will be granted fee-exempt allocations of imported oil equal to 75 percent of their additional inputs for the first five years of operation. These exempt allocations would be in addition to any fee exemptions which the company had already received.

ECONOMIC REQUIREMENTS

The total capital costs of the tankers required to carry future imports will depend on the size tanker which is employed. The NPC has estimated that, assuming the use of vessels averaging 250,000 DWT, over 400 tankers would be required. At a cost of \$36 million each (currently quoted for foreign construction) there would be total capital requirements, in terms of 1970 dollars, of \$14 billion by 1985. The assumption was made, however, that all waterborne imports would be coming from the Persian Gulf. For every million barrels/day from North or West Africa, the investment in tankers could be reduced by \$0.6 billion. Thus if one to two million barrels/day comes from Africa, capital investment would be about \$13 billion. 1/ There would also be a reduction for waterborne imports originating in the Western Hemisphere. The \$13 billion to \$14 billion represents, therefore, a maximum value. The NPC estimates that additional terminal and transportation costs will require capital investment on the order of \$2 billion (1970 dollars) through 1985. 2/

1/ NPC, p. 283.

2/ NPC, p. 295.

Any expansion of United States refinery capacity will require capital investments. Providing the maximum refinery capacity through 1985 would require an increase in crude runs of about 14 million barrels/day. This would necessitate the construction of 15 to 16 million barrels/day of net new refinery capacity at a capital cost of about \$30 million (1970 dollars). 1/ The minimum refinery case could be met with existing capacity. There would, however, still be significant capital requirements for the replacement of old or obsolete equipment.

Balance of Payments

Petroleum imports and associated activities have been an important factor in United States balance of payments. Imports of oil and refined products in recent years have equalled, in value, roughly 7 percent of all imports. The petroleum industry has accounted for approximately 25 percent of U.S. net capital outflows and 33 percent of U.S. net earnings abroad. 2/ Table VII-2 shows the balance of trade in energy fuels for 1970, 1975, and 1985. These estimates are based on their Case III situation.

1/ NPC, p. 280.

2/ NPC, p. 297.

	<u>1970</u>	<u>1975</u>	<u>1985</u>
Oil Imports (Delivered) <u>1/</u>	-3.4	-12.9	-20.4
Natural Gas and LNG Imports	-0.2	- 0.5	- 5.3
Total Energy Fuels Imports	-3.6	-13.4	-25.7
Oil Exports	+0.5	+ 0.4	+ 0.4
Steam Coal Exports	+0.1	+ 0.2	+ 0.3
Metallurgical Coal Exports	+0.9	+ 1.3	+ 2.1
Total Energy Fuels Exports	+1.5	+ 1.9	+ 2.8
Balance	-2.1	-11.5	-22.9

Source: NPC, p. 298 and p. 302.

One of the major assumptions used by the NPC was that the f.o.b. oil prices in 1975 and 1985 will be no higher than projected 1975 prices under currently existing contracts. Members of the Organization of Petroleum Exporting Countries (OPEC) have recently increased the posted price of crude oil, which are used to determine royalties and taxes that companies pay. This increase in tax payments by the companies is likely to result in higher f.o.b. oil prices. The NPC estimates may, therefore, prove to be conservative.

Another important factor in balance of payments is the secondary trade stimulated by the purchase of petroleum. U.S. dollars which are used to purchase fuel or to finance overseas operations will generate return flows when the energy exporting country spends part

1/ Including synthetic gas feedstocks.

of its increased income on U.S. goods and services. These return flows may come directly from the first recipient of the U.S. dollars or indirectly through third or fourth party countries. In balance of payment considerations, the direct first-round returns are most important. The level of first-round return flows from an exporting country can be estimated by the country's average propensity to import from the United States. The propensity to import factor indicates what portion of each dollar can be expected to return in direct purchases of U.S. goods and services in the short-term. Table VII-13 shows the average propensity to import from the U.S. of major oil exporting nations. It should be noted that as the primary source of imports shifts from the Western Hemisphere to Eastern Hemisphere, the first-round return on each dollar will decrease.

SECURITY CONSIDERATIONS

In 1970, a comprehensive study of oil imports was done by the Cabinet Task Force on Oil Imports Control. The Task Force's report, entitled The Oil Import Question, identified eight major security difficulties that might attend dependence on foreign supplies.

- "(1) War might possible increase our petroleum requirements beyond the ability or willingness of foreign sources to supply us.
- (2) In a prolonged conventional war, the enemy might sink the tankers needed to import oil or to carry it to market from domestic production sources such as Alaska.

Table VII-13

Average Propensities to Import from the United States 1/

Algeria.	0.062
Indonesia.146
Iran <u>2/</u>178
Iraq111
Kuwait208
Libya.166
Nigeria.116
Saudi Arabia291
United Arab Republic <u>2/</u>514

Source: U.S. Department of Interior, An Analysis of the Economic and Security Aspects of the Trans-Alaska Pipeline, Vol. I, p. F-3, (December, 1971)

- (3) Local or regional revolution, hostilities, or guerilla activities might physically interrupt foreign production or transportation.
- (4) Exporting countries might be taken over by radical governments unwilling to do business with us or our allies.
- (5) Communist countries might induce exporting countries to deny their oil to the West.
- (6) A group of exporting countries might act in concert to deny their oil to us, as occurred briefly in the wake of the 1967 Arab-Israeli War.
- (7) Exporting countries might take over the assets of American or European companies.
- (8) Exporting countries might form an effective cartel raising oil prices substantially." 3/

-
- 1/ Directions of Trade, IMF. Averaged over trade data for 1962-67. No clear trends were discernible, hence the recent average may be taken as an adequate approximation to the marginal propensity.
 - 2/ A significant fraction of the trade of Iran and the U.A.R. with the United States is financed by U.S. sources. Consequently, the balance-of-payments effect of U.S. trade with both countries is reduced by partly compensatory transactions on capital account.
 - 3/ Cabinet Task Force on Oil Import Control, The Oil Import Question, (February, 1970) p. 31.

Since the completion of The Oil Import Question, several of these problems have developed. The creation of OPEC has resulted in an effective cartel and brought about great increases in the posted price of crude oil. The October 1973 Middle Eastern conflict physically interrupted the flow of oil through some ports for a brief period. More importantly, since the end of October the Organization of Arab Petroleum Exporting Countries (OAPEC) has imposed a boycott on oil shipments to nations which, in their estimation, have been friendly to Israel, including the United States. Although there have been leakages out of the exporting countries, the boycott has resulted in an overall reduction in supply for all consuming nations. This has caused some nations to modify or change their diplomatic posture.

The Oil Import Question identified three possible types of alternative measures to cope with an interruption of supply. These are: using synthetic sources of crude, such as oil shale or tar sands; developing the shut-in capacity of Naval Petroleum Reserve No. 4; providing a means of storing oil. The potential of synthetic sources of crude oil and the NPR #4 reserves are discussed in other parts of this document. The most promising methods of storing oil are in steel tanks or in salt domes.

Estimates made in 1970, of the capital costs of storage in steel tanks range from \$1.84/barrel to \$2.75/barrel, including land acquisition. Annual management and repair costs would be 11-14 cents/barrel. Evaporation losses in a cone roof tank would be about 2 percent. However, if a floating roof were used, evaporation losses should be negligible. 1/

In the United States, salt domes are presently used for the storage of natural gas liquids. A 1966 study by the Department of the Interior indicated that there were, at that time, 130 unused onshore salt domes suitable for storage in the Gulf Coast area. 2/ The Interior Department assumed a potential storage capacity of five million barrels at each site, yielding a total capacity of 650 million barrels. The capital cost of salt dome storage was estimated to be \$1.02/barrel to \$2.04/barrel. Because there is no evaporation loss and only minor maintenance and management costs, total annual costs would be low. There would be some loss of oil in the recovery process. The Interior Department assumed a five percent loss in ultimate recovery. 3/

1/ Oil Import Question, p. 299.

2/ Bureau of Mines, "Salt Domes in Texas, Louisiana, Mississippi, Alabama, and Offshore Tidlands: A Survey, 1966" (IC 8313).

3/ Oil Import Question, p. 301.

Proposals have been made to establish a national petroleum reserve to guard against interruptions in the supply of foreign oil. These proposals would involve establishing storage areas, requiring holders of Federal oil and gas leases to maintain excess capacity by producing at less than their maximum efficient rate, and the getting aside of certain areas for petroleum reserves. The Santa Barbara Channel OCS has been suggested as a possible petroleum reserve area.

The establishment of a national petroleum reserve would require an increase in imports in the short-run. These imports would either go directly into storage or replace domestic crude oil which would be stored or held in reserve.

ENVIRONMENTAL IMPACT

The consideration of environmental impacts in this analysis primarily relates to additional ship traffic and oil handling associated with the increased level of imports.

Potential Oil Pollution

Three factors are considered in analyzing possible oil pollution related to tanker shipment of imports: (a) intentional discharge, (b) accidental discharge, and (c) casualty analysis.

Intentional Discharge

The two primary sources of intentionally discharged oil are shoreside ballast treatment facilities and underway tank cleaning operations. 1/ Any development of ballast treatment facilities would be accomplished at the loading end of the system. It may be assumed that all intentionally discharged oil in U.S. waters from this alternative will come from tank cleaning operations.

To assess fully the impact of tank cleaning operations, three separate analyses are necessary. While the overall average discharge rate in 1969-1970 was 0.074 percent of cargo, uncontrolled operations averaged 0.46 percent, load-on-top (LOT) averaged 0.027 percent, and the IMCO standard proposed in the 1969 amendments to the 1954 Intentional Convention for the Prevention of Pollution of the Sea by Oil was 0.0067 percent (one part in 15,000). Oceanborne imports in 1975 are expected to be 4.1 million barrels/day; in 1980, 6.1 million barrels/day; and in 1985, 10.7 million barrels/day. The following table shows the expected oil spill level under the three conditions:

1/ USDI, Trans-Alaska Pipeline System, Environmental Impact Statement
op. cit.

Potential Intentional Oil Spill Levels (thousand barrels/day)

	Oceanborne Imports	Uncontrolled Operations	L.O.T. Operations	IMCO Standards
1975	4100	18.9	1.1	0.3
1980	6100	28.1	1.6	0.4
1985	10700	49.2	2.9	0.7

Accidental Discharge

The 1970 Pollution Incident Reporting Systems (PIRS) data indicate that approximately 0.0015 percent of the oil handled in the U.S. was spilled during transfer operations. 1/ Applied to the projected throughput for 1975, 1980, and 1985, this would indicate spills of 61 barrels/day, 91 barrels/day, and 160 barrels/day respectively.

In the restricted waters surrounding harbors and ports, the 1970 experience indicates that about 0.00009 percent of the oil handled is accidentally discharged. 2/ This would indicate spills of 3.7 barrels/day in 1975, 5.5 barrels/day in 1980, and 9.6 barrels/day in 1985. .

1/ U.S. Coast Guard, "Marine Transport Systems of the Trans-Alaska Pipeline System", 1972.

2. Ibid.

Casualty Analysis

The worldwide tanker casualty analysis indicates that an insignificant amount of the total volume of oil transported is spilled, exclusive of transfer operations. ^{1/} The environmental impact could be nominal where small spills are involved or where the spill occurs in such a manner as to have little impact on coastal or restricted water areas. By contrast, a single catastrophic incident such as the breakup of the Torrey Canyon can have disastrous results. The oil spill problem is a subject involving considerable study effort. The first report of the President's Panel on Oil Spills presents considerable details relative to the subject.

Increased Tankers and Terminals

Increased petroleum imports will require an increase in the number and/or size of tankers. The heavily populated Northern Atlantic coastal region will be the primary destination of petroleum shipments with the Gulf Coastal region being the secondary location. If the use of conventional ports continues, tankers will generally be restricted to 60,000 DWT or less. As shown earlier, the continued use of these small tankers will require

^{1/} USDI, Trans-Alaska Pipeline System, op. cit.

a significant increase in the number of tankers to be unloaded each day. This added congestion would increase the risk of collision and subsequent oil pollution. The transfer of oil from VLCC's to small tankers at foreign ports would also cause substantial increases in ship traffic. The problems of port congestion could be alleviated through the use of large tankers making deliveries directly to U.S. terminals.

The environmental impacts of a terminal to handle large tankers will be determined by its location. Enlarging the channels and harbors of existing ports would require dredging which could endanger sensitive estuarine areas. These areas are important as nursing grounds for many species. Extensive dredging also presents the danger of penetrating freshwater aquifers and causing saltwater contamination of a major city's water supply. Expansion of existing port facilities in populated areas could cause conflicts with existing or planned land uses.

Offshore terminals would greatly reduce the dangers of dredging and port congestion. The determining factor would be the facilities' distance from shore. Terminals which are sited closer to shore will generally require a greater amount of dredging. Such a facility could, therefore, cause some damage to estuarine areas as a result of dredging and from oil spills which could reach shore before

dispersing or being cleaned up. A terminal further offshore could obviate the need for dredging and allow spills to disperse or be cleaned up before reaching sensitive areas.

The construction of a breakwater or island will permanently eliminate from productivity the area of seafloor and volume of water it occupies. Some of this loss will, however, be offset by fish havens formed by the rubble mounds and structures. A deeper offshore setting would again be preferable because it would affect fewer species. A breakwater could reduce wave action at the shoreline and thereby reduce erosion of the beach. This could lead to the deposition of suspended sediments and accretion of the beach. Continued accretion could cause the development of a sand spit, which may ultimately extend to the offshore structure. If this accretion were located at the upper end of the beach system, the normal supply of sand would be cut off and erosion of the beach would occur. Generally, if the distance from shore is more than twice the length of the structure, the effect on the shoreline would be minimal. 1/

1/ Maritime Administration, Executive Summary, p. 19.

Pollution Potential at Loading Site

The increased movement of petroleum will also result in increased oil spills at the loading end. These spills will, as at the receiving end, result from intentional and accidental discharges and tanker casualties, such as collisions, groundings, etc. In some exporting countries pollution control standards may not be as stringent as United States standards, and thus there may be a greater potential for pollution at some loading sites.

RELATIONSHIP OF ALTERNATIVE TO PROPOSED OCS SALE

Under this alternative, the replacement of the total energy expected from this sale would require additional oil imports of 166,000 to 279,000 barrels a day. If 29,000 DWT tankers were used (the average size tanker calling at U.S. ports in 1972), there would be about one additional tanker unloading each day. If 60,000 DWT tankers were used (the maximum size tanker which can presently enter U.S. ports), one additional tanker would have to be unloaded every other day.

The imported oil would go predominantly to the North Eastern U.S., with a small amount possibly going to the Gulf Coast region. Importing petroleum would have a negative impact on the United States balance of payments. Some of the factors affecting this impact are: the type of import, i.e., crude oil, semi-refined products, or refined products; the price of imported oil; the exporting countries' propensity to import from the U.S.; the amount of U.S. capital invested in the exporting country for production, transportation and terminal facilities, and the amount of U.S. goods and services used in the exporting country for these facilities; and the nationality of vessels carrying the oil. In the past, imported petroleum was generally less expensive than domestically produced petroleum. Recently, the price of foreign oil delivered to the U.S. has risen to a level

equal to or greater than that of oil produced on the OCS.

The primary environmental hazard of increased oil imports is the possibility of oil spills. Spills can result from intentional discharge, accidental discharge, and tanker casualties. Intentional discharges would result largely from tank cleaning operations, which in 1969 to 1970 had an overall discharge rate of 0.074 percent of cargo. At this rate, import levels of 166,000 to 279,000 barrels a day would result in discharges of 123 to 206 barrels a day. In 1970 approximately 0.0015 percent of oil handled in the U.S. was accidentally released during transfer operations. At this rate, 2 to 4 barrels a day would be accidentally spilled. The worldwide tanker casualty analysis indicates that, overall, an insignificant amount of the total volume of transported oil is spilled due to tanker accidents. However, a single incident such as the breakup of the Torrey Canyon can have disastrous results. With increasing tanker traffic in already crowded harbors, the probability of such an incident is increased.

b. Natural Gas Imports

As shown in Section IA of this report, domestic production of natural gas will have to be supplemented in order to fulfill demand. These supplements will come in the form of synthetic gas from coal and/or liquid hydrocarbons or as imports. Synthetic gas has been discussed in Section IV. Natural gas imports could come into the United States via pipeline from Canada or Mexico or as tanker-borne liquefied natural gas (LNG) from other countries.

PIPELINE NATURAL GAS IMPORTS

Pipeline imports of natural gas into the United States have come from the two bordering countries of Canada and Mexico. In 1972, 1.0 trillion cubic feet were imported, via pipeline, from Canada, while 0.008 trillion cubic feet came from Mexico. A relatively small proven natural gas supply base and a policy of "self-sufficiency in energy" indicate that potential new gas will probably not be available for export from Mexico. Present contracts expire in 1982; thus if no new supplies of gas are released for export, significant natural gas imports from Mexico could cease at that time. ^{1/} Future increases in pipeline imports of natural gas will, therefore, have to come from Canada.

^{1/} Federal Power Commission, Bureau of Natural Gas, National Gas Supply and Demand 1971-1990 Staff Report No. 2, Feb. 1972, p. 57, also Tables 25 and 26, p. 140.

based on actions by the Canadian National Energy Board (NEB), it appears that future increases in natural gas exports from Canada may be limited. In November, 1971, the NEB dismissed three applications for licenses to export over a 15 to 20 year period nearly 2.7 trillion cubic feet of gas to the United States. The NEB rejected the applications because "...the Board decided that there was no surplus of gas remaining after due allowance had been made for the reasonably foreseeable requirements for use in Canada...." 1/

The NEB's determination that there was no surplus of gas was based on the method used for calculating the required supply. The Board makes determinations of both current and future natural gas supply when considering export applications. Under NEB requirement the current gas supply should be adequate to meet authorized deliveries under existing export licenses as well as current Canadian domestic demand for almost 30 years. On this basis, in 1971, there was a supply deficiency of 1.0 trillion cubic feet. The future supply must be adequate, based on a given level of annual reserve additions, to protect existing export licenses and to maintain a reserve to production ratio of approximately 30 for Canada's projected domestic requirements for 20 years into the future. If

1/ Canadian National Energy Board's Annual Report, December 31, 1971.

projected gas supply exceeds projected supply requirements, an exportable surplus results. FPC calculations based on the historical finding rate of 3.5 trillion cubic feet per year, show that supply could fall 23.4 trillion cubic feet short of these requirements. 1/

Recent discoveries in the Arctic Islands, Mackenzie Valley, and Atlantic offshore regions will eventually, however, result in larger reserves additions. The NEB will not consider these new discoveries in its reserve calculations until they have been developed sufficiently to be within economic reach. If the discoveries continue and are developed, major surpluses may become available for export by the end of this decade.

1/ FPC, p. 51.

Table VII-14 shows various projections of pipeline imports from Canada.

Table VII-14
Pipeline Imports from Canada
(Trillion cubic feet)

	<u>1975</u>	<u>1980</u>	<u>1985</u>
FPC <u>1/</u>	1.2	1.6	1.9
Interior <u>2/</u>	2.0	3.0	4.1
NPC <u>3/</u>	1.0	1.6	2.7

The environmental impacts of pipeline construction and operation have been discussed in Section II-A. The impacts of pipelines carrying gas from Canada and Mexico would be essentially the same.

1/ Federal Power Commission, p. 55.

2/ Department of the Interior, U.S. Energy Through the Year 2000, p. 45, (Includes Mexican Imports).

3/ National Petroleum Council, U.S. Energy Outlook, p. 267.

LIQUEFIED NATURAL GAS (LNG) 1/ IMPORTS

Projections of Import Levels

Because of the growing shortage of domestic gas supplies, plans are now being made by the gas industry for baseload LNG imports under long-term contracts. LNG imports cannot, however, simply be increased to meet the demands for greater supplies of natural gas. Large scale shipping of LNG is a relatively new industry and the United States does not yet have facilities for receiving baseload shipments. The FPC recently approved two projects which together call for deliveries of the equivalent of more than 1 billion cubic feet/day of LNG. Several other projects have been proposed and are pending approval. Future import levels will, therefore, be dependent on the rate of buildup of the United States' LNG industry. The following table shows various projections of LNG imports.

^{1/} Natural gas becomes a liquid at -259°F at atmospheric pressure.

Table VII-15
(Trillion Cubic Feet)

	<u>1975</u>	<u>1980</u>	<u>1985</u>
FPC <u>1/</u>	0.3	2.0	3.0
Interior <u>2/</u>	0.5	0.9	1.6
NPC <u>3/</u>	0.24	2.28	4.11

Source and Destination of Imports

In 1971, non-Communist natural gas proved reserves were estimated to be 1,033 TCF and production was 138 TCF. The estimate of future discoverable reserves was 6,167 TCF. 4/ It appears, therefore, that sufficient supplies of natural gas will be available for export to the United States. Table VII-16 shows NPC's estimate of maximum LNG imports and a breakdown by source country. The second column shows the calculated backup of reserves necessary to support the estimated level of exports to the U.S. (based on 12.5 billion cubic feet of reserves for each million cubic feet per day of export) and the third column shows proved reserves as of January, 1971. Even without further discoveries, these countries appear to have sufficient reserves to support exports to the United States.

1/ FPC, p. 70.

2/ USDI, p. 45.

3/ NPC, p. 286.

4/ NPC, p. 264.

Table VII-16

1985 LNG IMPORT PROJECT SUPPLY

<u>Country</u>	<u>LNG Projects (MMCF/Day)</u>	<u>Calculated Reserve Backup (TCF)</u>	<u>1/3/71 Reserve Estimate</u>
Algeria	4,350	54.4	106.5
Nigeria	3,500	43.8	40.0
Venezuela	1,000	12.5	25.4
Trinidad	300	3.8	5.0
Ecuador	400	6.3	6.0
Pacific	1,000	12.5	42.9

Source: NPC, p. 266.

The one baseload project which has been approved by FPC will obtain LNG from Algeria and deliver it to the U.S. East Coast (Cove Point, Maryland and Savannah, Georgia). As indicated in the table above, supplies will be obtained from countries in all parts of the world. LNG receiving points will be primarily located on the East Coast, with other projects on the Pacific and Gulf Coasts.

TECHNOLOGICAL PROCESSES

The primary advantage of liquefying natural gas is the more than 600 to one volume reduction which results. LNG was first used by gas utility companies for peak shaving and satellite facilities and for remote and emergency deliveries. With the development of technology for marine transportation of LNG, large new sources of natural gas have become available to the United States.

Several processes exist for liquefying natural gas. Two primary methods are: 1) the transfer of heat through separate refrigerants to air or water; and 2) permit the gas to do work through the use of an expander. The first method, known as a cascade cycle, utilizes refrigerants of successively lower boiling points. The second method, known as an expander cycle, utilizes the cooling effect obtained by expanding a stream of compressed gas through a turbine or engine to extract work. 1/

Insulated storage is required for the LNG both after it has been produced and before it is regasified. The most frequently used storage tanks for baseload operations have been above ground, double-wall metal tanks. The space between the walls

1/ FPC, p. 63.

is filled with insulation, a partial vacuum or both. Prestressed concrete tanks have been used for other cryogenic fluid storage and may be applied to LNG. Testing has shown that the compressive strength of moist concrete at -150°F to -250°F is almost triple that of concrete at room temperature. 1/

There are at least four configurations for LNG ocean tankers. The "freestanding" system utilizes self supporting tanks which rest in the ship's hold and are independent of the hull. Insulation of this type is either on the outside of the tanks or the inside of the ship's hull. The membrane type uses the ship's hull as the tank wall with insulation attached to the hull. Another system incorporates five spherical cargo tanks, which are designed to reduce cost by requiring less insulation. All the above systems usually carry LNG at atmospheric pressure. Another tanker concept would carry medium condition liquefied gas (MLG) in cargo bottles at a temperature of -175°F and 200 Psig.

LNG is regasified by circulation through tubes. The heat for the process is obtained from the surrounding air or water, or is produced by the combustion of a fuel, such as some of the natural gas itself. After LNG has been regasified it can be introduced into conventional natural gas pipeline systems.

1/ NPC, p. 65.

Economic Considerations

Table VII-17 gives an indication of the capital costs which will be involved in the importation of LNG. Also shown in the table are potential source and destination points, import volumes, and the number of tankers required. Additional capital will be required for pipelines to connect the regasification plants with existing pipelines. This cost will be dependent on the location of the plant and of the pipeline. Pipeline construction for the Cove Point plant will require \$89 million, while pipelines for the Savannah plant will cost \$25 million. 1/

LNG imports will also have an impact on United States balances of payments. At this point in the development of the program it is difficult to determine what this impact will be. Capital from the United States will undoubtedly be involved in the construction of liquefaction plants. The Export-Import Bank, for example, is providing some of the funds necessary for the construction of an Algerian plant. It has not been established, however, just how much U.S. capital, will move to exporting countries or how much money will return through the purchase of U.S. equipment. The use of foreign or domestic tankers will

1/ Federal Power Commission, Docket No. Cp 71-68.

Table VII-17

LNG CAPITAL REQUIREMENTS FOR LIQUEFACTION, TRANSPORTATION AND REGASIFICATION--ALL CASES
(Millions of Constant 1970 Dollars)

Period	Voyage Route		Quantity BCF/Day	Round Trip Nautical Miles	Ships Required	Capital Requirements Millions Dollars			
	Source	Delivery Point				Ships	Liquefaction Plant	Unloading Terminal	Total Capital
Last Half 1975 1)	Algeria	- Cove Point	.350	7,300	3	150	131	49	230
	Total by End of 1975		.350		3	150	131	49	239
Additional 1976 - 1980	Algeria	- Cove Point	.300	7,300	2	117	120	54	291
		- Savannah	.500	7,900	4	220	175	56	451
		- Delaware River	.900	7,200	6	349	291	66	706
		- New York	.300	6,900	2	114	120	53	287
	Nigeria	- Delaware River	.650	9,800	6	337	222	60	619
		- New York	.200	9,700	2	106	91	46	243
		- Chesapeake Bay	.350	9,800	3	176	131	56	363
		- Boston	.300	9,500	3	158	120	50	328
	Venezuela	- Delaware River	.500	3,900	2	118	175	59	352
		- Lake Charles	.500	3,800	2	116	175	59	350
	Trinidad	- Lake Charles	.300	3,800	2	85	120	43	248
	Alaska	- Portland	.300	2,500	2	106	120	40	266
	Ecuador	- Los Angeles	.500	6,500	3	117	175	59	411
	Total Additional 1976-1980		5.600		39	2,179	2,035	701	4,915
Additional 1981 - 1985	Algeria	- New York	.500	6,900	3	183	175	61	419
		- Delaware River	.250	7,200	2	104	104	48	256
		- Chesapeake Bay	.500	7,300	4	211	175	55	441
		- Boston	.250	6,600	2	100	104	46	250
		- Savannah	.250	7,900	2	110	104	50	264
	Nigeria	- New York	.500	9,700	4	245	175	61	481
		- Delaware River	.500	9,800	4	248	175	61	484
		- Chesapeake Bay	.250	9,800	2	124	104	55	233
		- Boston	.250	9,500	2	121	104	54	279
		- Savannah	.250	9,900	2	124	104	55	283
	Pacific	- San Francisco	.500	13,200	6	341	180	58	579
		- Los Angeles	1.000	13,000	11	659	329	68	1,056
	Total Additional 1981-1985		5.000		44	2,570	1,833	672	5,075

Source: National Petroleum Council, op. cit., p. 294.

1) Due to delays in licensing, the 1975 delivery level may not be achieved.

also be a factor in the balance of payments. The cost of the gas itself will, however, probably have the greatest influence on balance of payments. One estimate of the f.o.b. price of gas is 38¢ to 53¢/Mcf. ^{1/} Importing 1 Tcf could, therefore, result in an outflow of \$380 to \$530 million. It should be noted that the various potential source countries represent a wide range of propensities to import from the U.S. (see Table VII-13 in previous section).

The price to the consumer of imported LNG is also difficult to project. The FPC, in approving the El Paso Natural Gas Co. application to import LNG, limited initial prices to 77¢ per million BTU's delivered to Cove Point, Md. and 83¢ to Savannah, Gas. The company has indicated that the allowed prices may be insufficient. The current prices for natural gas in the United States, under the area rate method, range from 22.5 to 34.0¢/Mcf at the wellhead. Under the FPC's new optional pricing system the price of new gas is higher. The first applications under this policy have proposed to sell gas for prices up to 55¢/Mcf.

^{1/} Amanullah R. Khan and William W. Bodle, "Supplementing United States Gas Supplies With Imported LNG," Journal of Petroleum Technology, May, 1972.

Environmental Impacts

The environmental impacts in the United States of LNG imports would be those of (1) tankers, (2) terminal, transfer, and regasification facilities, and (3) transportation and combustion of the gas.

Tankers

Any seagoing vessel may be involved in collision or other mishap. However, escape of LNG to the environment would not necessarily result in significant impact. Since LNG remains liquid only at -259°F at atmospheric pressure any spilled LNG would immediately begin to vaporize and, although it would pollute the air, would have little impact on land or water resources. Studies on the possibility of violent reactions upon contact between LNG and water resulting from LNG spills are inconclusive. Tests conducted during 1969 produced several instances of violent reactions upon contact between LNG and water. No fire or ignition of vapor was observed, but there was a rapid upward movement of gas accompanied by a loud "bang". ^{1/} A later study concluded that there was little danger of a violent reaction between normal LNG and water, and that such a reaction could result only after the methane content of the LNG had reached 40 percent. Since the normal methane content

^{1/} USDI. Bureau of Mines, "Hazards Associated With the Spillage of Liquefied Natural Gas on Water", Nov. 1970, p. 23.

of LNG is 80-90 percent or more and the boil-off rate is 0.2 percent per day, a reduction to 40 percent is not likely under current shipping practices. ^{1/} In the case of a large spill, the quantity of LNG remaining after weathering into the critical composition range could be significant. However, during the weathering period, the LNG will have spread on the surface and the chance of a single large reaction is relatively small. Since no chemical reaction is involved the energy available for a reaction is limited to the amount of super heat achieved during the time of direct liquid-liquid contact.

Transfer and Storage

Each regasification plant will require facilities to permit the transfer of LNG from tankers to storage areas. In the Cove Point case, this will be accomplished by the construction of a milelong pipeline into the Chesapeake Bay. At the proposed Savannah plant a channel and a turning basin would be dredged in the Savannah River to allow the tankers to come close to the plant. Both of these methods will require initial dredging, and possibly continued dredging, causing increased turbidity of the water and disruption of marine animals, especially in the case of bottom dwelling organisms. In most cases this disruption would be temporary, but care would have to be taken to

^{1/} Tholief Enger, "Rapid Phase Transformation During LNG Spillage of Water," paper presented before The Third International Conference and Exhibition on Liquefied Natural Gas, September 1972.

avoid, as much as possible, commercial fishing areas. The potential for fire or explosion is always present during the transportation, transfer, or storage of LNG. Since spilled LNG would not vaporize instantaneously, the release of the equivalent of several million cubic feet of gas, for example, might cause a fire which could continue until all the LNG had vaporized. An early LNG plant was destroyed by a disastrous fire in 1944 due to the failure of a storage tank, with a loss of more than one hundred lives. Since then, many improvements have been made in the technology of storage and handling of the LNG and increased attention has been given to proper safety precautions. The recent explosion of a Staten Island storage tank, killing more than 40 men, shows that there is still, however, an element of danger involved in the storing and handling of LNG.

Regasification

The construction of regasification plants will have an impact on land resources. The extent and duration of the impact will depend on the size and location of the plant. For example, the plant proposed for Cove Point, Md., would produce initially 650 million cubic feet per day and require a 1,022 acre tract of land; another plant proposed for Savannah, Georgia, would

produce initially 335 million cubic feet per day and require 860 acres, or 1.5 to 2.5 acres per mmcf capacity. During construction there will be some disruption of the land surrounding the plant, and some damage to animal habitats. This damage will be permanent only in the area occupied by the plant and supporting facilities.

Since natural gas or water will be used to regasify the LNG, very few pollutants will be released to air or water. Plants using water to regasify LNG will release the water at a lowered temperature. In the case of the Savannah plant, water temperature will be lowered 5° F. before being returned to the river.

A reasification plant could have an impact on the scenic and recreational resources of an area. The choice of the plant site is an important factor in minimizing the impact on scenic qualities and recreational activities. The increase in ship traffic could have an effect on water-oriented recreational activities.

Impact of Combustion and Transportation

Since natural gas is a relatively clean burning fossil fuel, the impact on air quality would not, therefore, be significant. LNG imports will require the construction of new pipelines. The impact of this construction has been discussed earlier in relation to domestic production of natural gas.

RELATIONSHIP OF ALTERNATIVE TO PROPOSED OCS SALE

This alternative would require natural gas imports of 0.93 to 1.57 billion cubic feet/day (0.34 to 0.57 trillion cubic feet/year) to replace the total energy expected from this sale. Projections of future natural gas import levels indicate a maximum level of natural gas imports of 3.9 trillion cubic feet/year in 1980 and 6.8 trillion cubic feet/year in 1985. Replacement of the energy from this sale by natural gas imports would, therefore, require a significant increase in the import levels.

Any increase in pipeline natural gas imports would have to originate in Canada. At the present time, the policy of the Canadian government has been to restrict the level of gas exports in order to build a large domestic reserve. Unless there is a change in this policy, it is unlikely that the necessary gas would be made available.

Increases in LNG imports will depend on how soon this industry can be introduced into the U.S. At the present time there are no base-load LNG projects in operation in the U.S., although one has been approved and others are pending approval. In view of the Middle Eastern oil cutbacks, the question of security of foreign LNG supplies has caused re-evaluation of these projects. To supply the energy expected from the sale with LNG imports would require the unloading of one 125,000 cubic meter tanker every two to three days and the construction of 3 to 5 350 million cubic feet/day regasification plants.

8. Other Energy Sources

The basic nature and occurrence of any energy source largely govern the technological opportunities and problems involved in its application. As research continues probing into the nature of numerous energy sources, many potential alternatives to conventional energy production are emerging. The existence of some of these sources has been known for decades, although unfavorable economics or incompletely developed technologies have hampered their commercial acceptance. Long range projections must take into account such potential sources of energy, since a major technological breakthrough in any number of areas could effect a considerable change in the current energy picture.

Environmental impacts of these more exotic alternatives are difficult to assess, particularly where there is a great amount of research and development that must be done before operational scale systems can be developed, tested, and evaluated for production application.

Lack of resources (due either to geographic location or lack of quantity and quality), underdeveloped technology, or lack of an economic advantage over conventional energy sources are the chief reasons these other sources are unlikely to have significant various availability before 1985. Below are summarized the various energy forms considered here in relation to their primary and secondary limitations.

I. Possible significant energy contribution before 1985

<u>Energy forms</u>	<u>Primary limitations</u>	<u>Secondary limitations</u>
Geothermal Energy	Resources	Economics
Tar Sands	Resources	Economics

II. Improbable significant contributions before 1985 1/

<u>Energy forms</u>	<u>Primary limitations</u>	<u>Secondary limitations</u>
Hydrogen	Economics	Technology
Biological (agri-cultural & wastes)	Economics	Resources
Solar	Technology	Economics
Tidal	Resources	Economics
Wind	Resources	Economics

Energy Conversion Devices

Fuel cells	Technology	Economics
Thermonics	Technology	Economics
Thermoelectric	Technology	Economics
Magnetohydro-dynamics	Technology	Economics

1/ After: New Energy Forms Task Group 1971-1985 National Petroleum Council Committee on U.S. Energy Outlook, 1972.

Federal energy research and development funding has expanded significantly in the last few years. President Nixon announced in his Energy Message of January 23, 1974, Federal commitment for direct energy research and development will be increased to \$1.8 billion in FY 75. The table below shows the funds for different areas of research and the agencies involved.

Federal Energy R&D Funding
(\$ million)

<u>Direct Programs</u>	<u>FY74</u>	<u>FY75</u>	<u>Agency*</u>
<u>Conservation</u>	<u>65.0</u>	<u>128.6</u>	
a. End use (Residential & Commercial)	15.0	27.9	DOI, other
b. Improved Efficiency (Transmission)	5.0	18.8	AEC, DOI, NSF
c. Improved Efficiency (Conversion)	14.9	29.8	AEC, DOI, NSF
d. Improved Efficiency (Storage)	2.9	6.4	AEC, NSF
e. Automotive	14.2	23.7	AEC, EPA, NSF, DOT,
			DOD NASA
f. Other Transportation	13.0	22.0	DOT, DOC
<u>Oil, Gas, & Shale</u>	<u>19.1</u>	<u>41.8</u>	
a. Production	3.0	17.0	DOI
b. Resource Assessment	5.0	13.1	DOI, NSF
c. Oil Shale	2.3	3.0	DOI
d. Related Programs	8.8	8.7	AEC, DOI
<u>Coal</u>	<u>164.4</u>	<u>415.5</u>	
a. Mining	7.5	55.0	DOI
b. Mining, Health, & Safety	27.0	27.7	DOI
c. Direct Combustion	15.9	36.2	DOI, NSF
d. Liquefaction	45.5	108.5	DOI, NSF
e. Gasification (High BTU)**	33.0	65.3	DOI, NSF, AEC
f. Gasification (Low BTU)	21.3	50.7	DOI, NSF
g. Synthetic Fuels Pioneer Prog.		42.1	DOI
h. Resource Assessment	1.2	1.9	DOI
i. Other (incl. Common Technology)	11.7	28.1	DOI

<u>Environmental Control</u>	<u>65.5</u>	<u>178.5</u>	
a. Near term SO _x	39.9	82.0	EPA, DOI
b. Advanced SO _x	4.0	12.0	EPA
c. Other Fossil Fuel Pollutants (incl. NO _x , Particulates)	13.1	57.0	EPA
d. Thermal Pollution	1.5	18.5	EPA, AEC
e. Automotive Emissions	7.0	9.0	EPA
<u>Nuclear Fission</u>	<u>530.5</u>	<u>724.7</u>	<u>AEC</u>
a. LMFBR	357.3	473.4	
b. Other Breeders (GCFER & MSBR)	4.0	11.0	
c. HTGR	13.8	41.0	
d. LWBR	29.0	21.4	
e. Reactor Safety Research	48.6	61.2	
f. Waste Management	6.2	11.5	
g. Uranium Enrichment	57.5	66.0	
h. Resource Assessment	3.4	10.4	
i. Other (incl. Advanced Tech.)	10.7	28.8	
<u>Nuclear Fusion</u>	<u>101.1</u>	<u>168.6</u>	<u>AEC</u>
a. CTR	57.0	102.3	
b. Laser***	44.1	66.3	
<u>Other</u>	<u>53.5</u>	<u>157.5</u>	
a. Solar	13.8	50.0	AEC, NSF
b. Geothermal	10.9	44.7	AEC, DOI, NSF
c. Systems Studies	17.3	30.0	AEC, DOI, NSF, FEO, Treasury, FPC, other
d. Misc.	11.5	32.8	NSF, DOI
<u>Support Programs</u>			
<u>Environmental Effects Research</u>	<u>169.7</u>	<u>303.4</u>	<u>AEC, EPA, NSF</u>
a. Pollutant Characterization, Measurement, & Monitoring	16.3	37.4	
b. Transport of Pollutants	26.6	55.6	
c. Health Effects	72.6	112.5	
d. Ecological Effects	27.3	65.0	
e. Social & Welfare Effects	17.5	19.8	
f. Environmental Assessment & Policy Formulation	9.4	13.1	

<u>Basic Research</u>	<u>94.5</u>	<u>174.6</u>	AEC, NSF
a. Materials	13.2	32.9	
b. Chemical, Physical, Engineering	30.8	58.1	
c. Biological	40.3	60.5	
d. Plasmas	2.8	8.2	
e. Mathematical	7.4	14.9	
<u>Manpower Development</u>	<u>6.3</u>	<u>8.5</u>	AEC, NSF
Total (Direct Energy R&D)	999.1	1,815.5	
Total (Support Programs)	270.5	486.5	
Total (Direct & Support)	1,269.6	2,302.0	

*Agency Codes:

AEC - Atomic Energy Commission
 DOC - Department of Commerce
 DOD - Department of Defense
 DOI - Department of Interior
 DOT - Department of Transportation
 EPA - Environmental Protection Agency
 FEO - Federal Energy Office
 FPC - Federal Power Commission
 NASA - National Aeronautics and Space Administration
 NSF - National Science Foundation

**Funds for High Btu Gasification in Office of Coal Research Budget do not include Trust Fund amounts.

***Includes amounts for laser fusion directed toward military applications.

a. Long-Term Sources

1. Geothermal Steam

a) Description of the Alternative

Introduction

The development of geothermal and associated geothermal resources involves the harnessing of the natural heat energy sources in the earth for the generation of electric power, and the production of commercially valuable by-products.

The use of geothermal steam as a source of energy is still, in large part, in the investigative stages. Commercial geothermal production in the United States to date is small, existing in only one area in The Geysers, California, and only since about 1960. Present exploration efforts are continuing mainly in the Imperial Valley, Morro Lake, Modoc County, California and Chandler, Arizona on private and public lands. There is currently no existing geothermal leasing program on Federal lands although proposals are under consideration. Developments in Italy have existed since about the turn of the century. Worldwide geothermal exploration and development in 1970 was limited to six fields with present capacity of about 1,000 MW. Development of geothermal resources is similar to oil and gas production operations except that it deals with water in the gaseous and fluid state, under pressure, produced from the earth through drilled holes. Operating plants for converting the steam to electrical energy consist of low pressure steam-turbine systems similar to those in use in the early

1920's. New technology should expand the use and adaptability of the resource beyond its current limitations.

In meeting future energy demand, the Nation must use many available sources of energy--coal, gas, oil, hydroelectric, and nuclear among the more important--and no one source is an exclusive alternative to any or all of the other sources. In this context, geothermal energy would hopefully be a feasible means of supplementing other forms of electric power generation on the local scale. Under present technology, and economics, and resource availability, however, geothermal cannot be expected to substitute for other forms of electric generation. Even under favorable assumptions, "United States Energy Through the Year 2000" (U.S. Department of the Interior, 1972) estimates that geothermal energy will comprise less than one percent of the national electric power capacity through the year 2000.

For a geothermal reservoir to have appreciable potential for exploitation, it must meet the following requirements: (1) relatively high temperature (greater than 105° to 400° F., depending on processing technology); (2) a depth shallow enough to permit drilling (currently 10,000 feet or less); (3) sufficient rock permeability to allow the heat transfer agent (water and/or steam) to flow continuously at a high rate, and (4) sufficient water recharge to maintain production over many years.

Geothermal reservoir systems can be categorized into either a vapor dominated system with a high yield of steam and little associated water, or hot water systems yielding only hot water which at high temperatures can flash to steam.

At the Geysers, geothermal steam electric capacity as of spring 1972 was 192 MW and an additional 110 MW came on line late in 1972, and 110 is subsequently scheduled in 1973, 1974 to reach a total of 552 MW. Beyond 1974, scheduled installation of at least 100 MW of new capacity per year could bring the production up to 1000-2000 MW which is the estimated ultimate capacity of the Geysers field. The success of this project is attributed to both favorable geologic conditions and heavy nearby demand for electrical generating capacity. The following table illustrates how this would replace an equivalent amount of oil needed. 1/

1/ Predicted geothermal power from National Petroleum Council, U.S. Energy Outlook, Vol. 2, 1971.

Table VIII

Oil requirement needed in Western United States to
replace electricity generated by geothermal means
(5.8 million Btu are assumed equivalent to 1 bbl. oil)

1971 OCS Production (oil + gas equivalency in Btu) = 914 mil. bbl. of oil

<u>Year</u>	<u>Geothermal Power</u>	<u>Oil Replacement million bbl./year</u>
1973	302 megawatts from Geysers Field, California	3.9
1980	1,000-2,000 megawatts from Geysers Field, California	13-26
1985	7,000-20,000 megawatts from all western U.S. sources (assuming new technology can be developed to use hot water).	91-260

Other favorable areas for prospecting exist on the Western United States. In California interest is chiefly in the Imperial Valley area and the Mono Lake-Long Valley area. Large amounts of land in Oregon, Washington, Idaho, and Montana are also classified as Known Geothermal Resource Areas (KGRA's). All of these areas are most likely hot water systems, rather than vapor dominated systems, and will require the disposal of large volumes of water creating additional environmental, technical, and economic problems, before large scale development can proceed.

Production

Production of a geothermal resource involves exploration for suitable reservoirs, test drilling, production testing, field development, and power plant construction and operation.

Exploration for suitable reserves would involve topographic and geologic mapping, ground and spring temperature surveys, geochemical sampling, geophysical surveys, and finally shallow drilling to measure temperature, ground water flow, and sub-surface rock sampling. These exploration activities are surface-oriented investigations and therefore are subject to control as to potentially significant environmental damage by the nature of Federal leasing laws.

Test drilling is necessary to obtain sub-surface geologic data and thereby delineate the size, shape, physical and chemical properties of the reservoirs, and the nature of reservoir fluids. Current drilling methods are similar to those used in oil and gas operations with some modifications. Both graded drilling sites and access roads would be needed to move the heavy drilling rigs, and supplies. During the drilling, provisions should be made for the control and disposal of drilling muds and fluids, prevention of blowouts, and containment of reservoir fluids, all of which have potential impact on the environment.

Production testing is the transitional phase between exploration and the development of potential production. A well that has penetrated a possibly productive geothermal zone is developed and tested over a period of time to both clean out the well and to determine a number of properties of the reservoir and fluids, i.e., flow rate, composition and temperature of the fluids, recharge characteristics, pressures and compressability. Sufficient time is necessary to establish various

hydrodynamic properties and possibly boundaries of the reservoir. Venting of the fluids or vapors during this phase could have an impact on the environment. Fluids must be properly channeled into ponds separated from local water courses and steam vapors must be muffled by special mufflers or discharged underwater to prevent intolerable noise levels. If toxic substances are associated with the well effluent, they must be controlled and, of course, access roads as well as other construction activities involved in maintaining production testing sites would be necessary.

Field development would begin after favorable exploration test, drilling and production testing programs. A systematic pattern of wells would be drilled in order to maximize the output of the reservoir and to minimize individual well interference. The patterns adopted would reflect the interpreted characteristics of each reservoir. The environmental considerations would be similar to the production testing phase with the exception that there would be more wells and they would be vented to a power facility rather than wasted to the earth's surface and atmosphere.

Power Plant and power line construction involves commitment of large amounts of capital and would require successful completion of all the pre-production phases. Careful evaluation of environmental effects must be made prior to this large scale commitment of capital. Steam can practically be transported only about one mile and this involves above ground insulated pipes due to pronounced thermal expansions and contractions during operation. Underground pipe systems are uneconomical due to service and equipment requirements. If the effluent from a geothermal well is hot water, contaminants in that water must be removed before fresh water can be produced. If contaminants are not removed the effluent must be reinjected rather than discharged into the surface water system. Subsidence of the ground surface over and around a geothermal reservoir could result from depletion of large volumes of fluids. In raising fluids through various rock strata care must be taken not to contaminate a previously

sealed fresh water aquifer. Material used in the construction should be made of suitable corrosion resistant material to help prevent spills and leaks. Finally, construction and development would involve a commitment to deplete thermal energy and water from a geothermal reservoir; although renewable, it will take longer than the life of a specific project.

b) Description of the Environmental Impact

Potential Environmental Impacts 1/

The favorable impacts of geothermal power production, aside from the obvious socially desirable effect of supplying energy to the nation, include improved access and fire protection in an undeveloped country. Service roads to wells also provide access for hunters, fishermen, and for recreation in general. Fire control measures are improved such as clearing of brush and fire fighting in many terrains and also improved feed from birds and animals is provided.

Industrial Intrusion - The principal objection to geothermal power development stems from the intrusion of industrial development into new areas. Nearby residents and outdoorsmen generally find the noise, odor, and disturbance of terrain and vistas highly objectionable. Such objections are understandable, and operators have been attempting to meet them by alleviating the objectionable aspects insofar as

1/ Final Environmental Impact Statement, Proposed Trans-Alaska Pipeline, Vol. 5, Department of the Interior, 1972.

practicable. However, some impacts are unavoidable and the public will have to decide whether the impacts are acceptable.

Fish and Wildlife - Test drilling and production testing of geothermal steam resources would have varied impacts upon fish and wildlife. Most would occur on or adjacent to well sites, although water quality impacts could potentially have further influences. The magnitude of particular impacts would be interrelated with fish and wildlife and their habitat within the area of development influences, extent and duration of the entire geothermal development activities and operations, and the effectiveness of control measures. Many of the impact types lend themselves to whole or partial control.

As a specific geothermal developmental proceeds through test drilling and production testing, physical land modification and commotion would occur. These activities would include such things as construction of roads, ponds, drill sites, and drilling of wells which would result in loss of wildlife values.

Most areas adjacent to drilling and test operations, but outside of the immediate zone of physical modification, would retain part or all of their fish and wildlife populations and habitat. Where existing public access would be restricted in order to reduce hazards to the public, there would be an accompanying reduction of hunting, angling, and camping opportunity on these lands. The importance of these losses would depend upon the capacity of other available habitat

areas to absorb the pressures which are presently absorbed by the geothermal area.

Erosion from roads and the construction activities would predictably result in added siltation of aquatic habitat within the area of project influence. This would be most severe during construction phases, although some might extend into the operational stages. Harmful siltation effects would include coverage of fish spawning and feeding areas as well as shoaling of streams. The degree and extent of siltation damage to aquatic habitat within the area of influence would be dependent upon the success of erosion control measures, amount of land disturbance, and type of terrain.

Blowouts - Blowouts, in which steam or water escapes uncontrolled, potentially pose a distinct environmental hazard in geothermal drilling. The principal adverse environmental effects of such accidental releases are safety of operating personnel, waste of the resource, noise nuisance, air contamination from gaseous emissions, and possible pollution of surface and ground water resources. Once a blowout occurs it is troublesome to control because of the difficulty in handling escaping hot fluid. However, unlike similar problems encountered in petroleum drilling, there is essentially no fire hazard in the case of a geothermal accident. To further minimize this hazard, proper casing design is required to assure that the pressurized fluid will be confined to the well bore and can be controlled through surface shut-in equipment.

Ground Water - The ground water regime in the general area of a geothermal field may be irretrievably altered if appropriate control procedures are not employed. A fresh water aquifer may occur above a geothermal reservoir which contains hot saline water. Tapping the geothermal strata could result in contamination of the fresh water if one horizon were not kept isolated from the other by properly cementing the casing of either production or reinjection wells. During the earlier stages of a project suitable data must be accumulated and analyzed, and studies made to determine what steps should be taken to prevent or minimize alteration of the area ground water regime.

Seismic Stimulation - Experience in petroleum production indicates that marked changes in reservoir pressure, whether due to pressure reduction from the production of fluids, or to pressure increase due to injection, may in certain types of reservoirs, especially in faulted or fractured rocks, result in instability leading to earthquakes. Such instability due to production alone has been documented in the Wilmington Oil Field, California (Poland and Davis, 1969, p. 205), instability due to injection was documented at the Baldwin Hills Oil Field, California (Hamilton and Meehan, 1970), at the Rangely Oil Field, Colorado (Healy and others, 1968), and in connection with injection of waste waters at the Rocky Mountain Arsenal, Colorado (Healy and others, 1970). Similar increases in seismic activity have also been noted in association with filling or large surface reservoirs with attendant change in hydrostatic head, including Lake Mead on the

Colorado River and Lake Kariba in Africa (Rothe, 1969, p. 215). The role of fluid-pressure changes in triggering seismic activity is not well known, but a causative relation has been established in many areas. In general, such activity has not proven disastrous, but the potential for a major quake cannot be ruled out. In any event, seismic activity must be counted as a potential environmental impact associated with geothermal development, and provisions must be made for seismic monitoring before and during major production. If monitoring indicates a significant increase in seismic activity particularly in intensity of motion, remedial steps to alleviate stress would have to be initiated promptly.

Subsidence - Subsidence of the ground surface over and around a geothermal reservoir can result from the withdrawal of large volumes of fluids. ^{1/} Subsidence would reach a maximum rate during full-scale operations unless fluid is returned to the reservoir. In some instances it may be practical to reinject the geothermal fluids after extracting most of their heat. Studies would be initiated prior to approval of operating plans to determine the existence of subsidence potential and its probable consequences. If fluids are not reinjected, subsidence measurements should be made during the course of a project, at intervals to be determined by the rate of potential subsidence, to determine whether remedial action would be required.

^{1/} Poland, J. F. and Davis, G. H., 1969, Land Subsidence Due to Withdrawal of Fluids, *Geologic Society of American Reviews in Engineering, Geology* II, p. 187-269. Hunt, T. M., Gravity Changes at Wairakei Geothermal Field, New Zealand; *Geologic Society of American Bulletin*, Vol. 81, p. 529-536.

Noise - Noise due to steam ejection or expansion can be severe and can be expected to reach its highest intensity during testing operations. Such noise can range from a low-frequency to a very high frequency region. Experiments at the Otake Geothermal Power Plants located in the Aso Mountains in Japan have shown that an ordinary expansion chamber muffler is not effective for high-frequency abatement. However, a newly designed muffler used at the Geyser geothermal area effected good noise reduction, even in the high-frequency region, and it did not cause much resistance to steam flow. Venting steam under water also reduced noise effectively.

Power Distribution - Distribution of electric power involves a wide scope of environmental impacts. However, because of the small scale of geothermal developments only the aspects of delivering electricity from the geothermal plant to existing electrical networks are properly assignable to the geothermal development. Normally this would involve construction of lines of 69 kv to 110 kv capacity to provide connection for power generated to the nearest main transmission line. The present practice is to use overhead steel tower lines.

Electrical transmission lines are generally benign and favorable environmental impacts would be limited mainly to improved fire protection resulting from clearing of the rights-of-way and slight improvement in access as well. The principal adverse impacts are aesthetic, due to the intrusion of the structures on vistas. Disturbance of the terrain is minimal except for clearing trees and brush. Transmission lines

located in flyways or over nesting and feeding sites would cause some mortality of waterfowl, raptors, and other birds from collision and/or electrocution. The magnitude of this type of loss cannot be predicted but would be expected to be minor with proper design and location of transmission facilities.

Waste Disposal - Solution to problems of waste disposal is vital to successful development of geothermal resources. Geothermal waste fluids normally contain sufficient mineral matter than discharging them into streams and lakes would be generally unacceptable. Even discharge to the ocean might be unacceptable in view of the thermal load. Disposal to otherwise usable underground waters likewise would generally be unacceptable. The solution available in most situations is reinjection of waste fluids into the producing zone. This has the double advantage of providing recharge and pressure maintenance to the geothermal reservoir, as well as providing for waste disposal. It might be possible to evaporate wastes and recover minerals and salts of economic value.

The favorable impacts of waste disposal through reinjection include pressure maintenance and recharge, which would tend to alleviate potential adverse impacts of land subsidence and increasing seismicity and instability resulting from reservoir pressure decline. Other favorable aspects of not polluting surface waters are self-evident.

With proper management of reinjection works, adverse impacts would be minimal. The potential adverse impact from improper management, how-

ever, includes both the pollution of surface and ground waters as well as for increasing seismic activity.

The major potential impact would be upon fish and wildlife which could result from improperly planned or executed handling of geothermal fluids. If controlled releases, spills, seepage or well blowouts were to result in significant additions of toxic or highly saline geothermal waters to streams, ponds, game management areas, etc., adverse impacts would result. These impacts would include the alteration of fishery habitat and waterfowl nesting and feeding areas over the area of influence. If toxic substances, such as boron, sulfides, methane, fluoride, arsenic, and others were present in such releases, they also would exert adverse impacts. Releases of heated effluents to aquatic habitat would alter aquatic habitat and life, perhaps creating temperatures intolerable to existing fish species and stimulating growths of nuisance algae.

Use of excessive pressure in injecting waste waters could conceivably increase seismic activity, but with adequate design and monitoring of reservoir pressure this problem should not be serious.

Another aspect of waste disposal not generally considered is that of gaseous wastes. Steam from cooling towers in some situations could bring on fogging problems, and this should be considered seriously in design and siting of such installations. Likewise release of noxious gases with such steam also constitutes an inverse impact,

but certain gases, particularly hydrogen sulfide and ammonia, can be removed from power plant steam before release.

Other Potential Benefits - There are indications that through the combination of desalination processes with energy production, large volumes of usable water could be produced. This could be of particular value in the water-short western state. There also is the potential of mineral production. The investigation of such potentials has only begun so the magnitude and economic feasibility cannot be evaluated at this time. However, it could be that such multi-purpose benefits would result in overall lower system costs that would further enhance the electrical generation potential of geothermal resources.

Summary - Geothermal energy will not be an alternative to traditional energy sources on a nationwide basis but will supplement these sources in areas near geothermal resources where high energy demand exists. Development and production of geothermal resources involve phases of exploration, test drilling, production testing, field development, and power plant and power line construction with full scale operation. Probable environmental impacts would consist of tearing up the landscape for access roads, drilling and construction sites with unsightly equipment and facilities. Construction and drilling debris as well as erosion will injure local water supplies. Occasional venting breaks with accompanying noise and atmospheric pollution will occur. Possible environmental impacts involve blowouts with subsequent noise and contamination, detrimental effects to fish and wildlife populations,

ground water contamination of fresh water aquifers, triggering seismic activity, including subsidence, contaminating the surface and atmosphere with hot toxic waters, and fog created from cooling geothermal waters. Beneficial impacts as a result of fresh water, improved access to lands, and mineral production are also a possibility.

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2. Tar Sands

a) Description of Alternative

Reservoirs of hydrocarbons that are too viscous to be recovered in their natural state and by conventional oil production methods are called tar sands or bituminous sands. Typically reservoir energy is nonexistent and for production to be significant other energy must be added in some manner, either by direct heating, fluid pressure, or mechanical work.

Of the many known North American tar sand deposits, only a few are likely to be of major commercial interest in the next 15 to 30 years. Chief among these are the Athabasca deposits in northern Alberta, Canada, and the Orinoco deposits in eastern Venezuela. 1/ Only five deposits in the United States of 0.5 billion barrels or more are worth considering in relation to affecting United States energy supply. All of these deposits are in Utah and are estimated to contain about 17.7-27.6 billion barrels of tar and resources in place, based on relatively few drill holes supported by outcrop data. Recovery would only be on the order of 30-50% of the in-place reserves, reducing these reserves to 10-16 billion barrels of recoverable oil. Another estimate of U.S. tar sand reserves, based on shallow occurrences only, range from 2.5-5.5 billion barrels of recoverable oil. 2/

1/ U.S. Energy Outlook, National Petroleum Council, November 1971.

2/ U.S. Bureau of Mines Monograph 12, 1965.

Production from Domestic Tar Sands - Three states have occurrences of tar sands; Utah, California, and Kentucky. Presently only in Utah is there any production potential, furthermore, the Utah deposits are not susceptible to mining, but more likely will be developed by in situ methods, the technology for which has yet to be developed. In either method, a major shortcoming is a lack of an adequate water supply in proximity to the deposits.

In addition to technological problems other legal and developmental problems exist. The Tar Sand Triangle and Circle Cliffs giant deposits are largely on Federal lands. Leasing of Federal lands for "asphaltic minerals" or tar sands has been delayed pending legislation.

Proposals for national parks, national monuments, desert wilderness areas and recreational areas cover most of the Circle Cliffs and Tar Sand Triangle giant deposits and could result in surface uses incompatible with mineral resource development. In the P.R. Spring giant deposit, the tar sands and shale oil deposits are superimposed, creating potential legal problems with long costly delays. Finally, lead time for mining ventures range from 4-7 years, for inception to full production, and can become an important consideration to production possibilities.

Canadian Production - The largest most accessible tar sand deposits occur in the Athabasca region of Canada. The NPC 1/ estimates that 174

1/ U.S. Energy Outlook, National Petroleum Council, Vol. II, 1971.

billion barrels may be economically recoverable. Others estimate as little as 85 billion barrels are minable. Canadian production is currently limited by licensing requirements in addition to technical problems but Canadian production by 1985 of 500,000 to 1,000,00 barrels per day is anticipated. Increasing sensitivity of Canadians to the environment and lack of a local Canadian market for the oil could cause considerable delay. 1/

Recovery Methods - National Petroleum Council 2/ study reached the following conclusion regarding production of tar sands by strip mining methods:

a. Mining Extraction

"The mining extraction route is most applicable to the shallow deposits (up to 100 or 150 feet of overburden). Because about 12% by weight, an immense tonnage of sand and overburden must be moved, using strip mining methods, to support an economically large synthetic crude output. On a unit basis, the ratio is about 2.4 tons of sand and 1.0 ton of overburden, more or less, per barrel of synthetic crude. Local variations in overburden ratio and/or tar sands quality over a given lease area can, result in condemnation, on economic grounds, but always respecting good conservation practice, of significant portions of a lease. Thus, an overall average utilization of total tar sands in a mining leasehold might be on the order of 75%."

1/ Oil Week, January 29, 1973.

2/ Op. cit., 1971.

b. In Situ Recovery

"The two methods most thoroughly researched and tested in the field involve (1) injecting steam plus an emulsifying agent (e.g., caustic soda as used in a Shell Oil Co. trial) into the deposit and (2) using thermal-recovery or 'fire-flooding' techniques, as experimented with Amoco (Canada) and others. For either method to succeed, communication must be established downhole in the formation between the injection wells and the production wells. Field tests have determined that this can be achieved. Overall recovery of in-place bitumen via either in situ technique is estimated to be on the order of 35 to 50%, distinctly lower than the corresponding value for mining extraction."

The mining extraction route has the option of being the more economical method per unit of area exploited but causes large scale surface disturbance in both the mining and the storing of mined material to be processed. In situ processing, although lower recovery per unit of area exploited, would leave no sand tailings disposal problem. Few large areas in the, U.S. would be susceptible to strip mining methods because of depth of overburden. Plans and techniques for underground mining are unknown at this time. The in situ method presently holds the greatest promise for recovery of the U.S. deposits.

Processing - Athabasca bitumen is a naphthene base, black material containing relatively large amounts of sulfur, nitrogen, and metals. With a specific gravity of 6 to 10 API and a viscosity roughly in the

range of 35,000 Saybolt Universal Seconds at 100° F., the material is unsatisfactory for feed to conventional oil refineries and impossible to ship via pipeline to distant refining centers. This necessitates some form of pre-refining in the field. To accomplish this "upgrading" of the bitumen some means of hydrogen-enrichment is needed and some fuel must be set aside for the pre-refining as well as for production of hydrogen.

In the process of hydrogen-enrichment, the sulfur and nitrogen contents are reduced to tolerable levels and the metals exist with the carbon residue leaving an acceptable to superior synthetic crude oil for shipment to ordinary refineries. The carbon residue is then recycled as a fuel for the pre-refining operation. Existing technology can provide the devices necessary to control particulate matter, sulfur dioxide, and nitrogen released into the atmosphere during this processing.

Many methods have been proposed for recovering oil from mined tar sand. Great Canadian Oil Sands LTD via coking and hydrogenation of coker distillates get a synthetic crude product/bitumen volume ratio of 0.78. Syncrude Canada Ltd., with hydrovis breaking plus hydrogenation of distillates gets a ratio of 0.87. The loss in product is accountable for by the material set aside for fuel and for production of hydrogen in the upgrading process.

b) Environmental Impact

Tar sand development would effect the environmental in all phases of development; exploration, mining, production, and transmission of the synthetic crude.

Exploration - Standard exploration techniques are likely to have an effect on the environment. Seismic disturbance associated with initial geophysical surveys delineating the extent of the prospective producing zone would temporarily disturb some domestic animals and wildlife in the area. Other sophisticated methods as gravity, and electromagnetics which are used to determine regional geological structure in the area would not likely disturb animal life. Exploration drilling would involve access roads, drilling sites, mud ponds, and unattractive storage areas. Soil erosion associated with this activity could effect local surface waters and the fish in them. Drilling operations could contaminate various subsurface aquifers by using certain drilling mud additives or intermixing saline and fresh water aquifers. Debris and wastes associated with any construction and drilling activity could have an impact on aesthetics, especially important in tar sand areas due to interest in land use for wilderness areas, recreational areas, national parks, etc.

Mining - Once exploration has determined an area to be profitable, a choice of using mining-extraction or in situ will have to be made. The mining-extraction method has the advantage of greater recovery,

but the environmental disadvantages of: a) large unsightly amounts of tailings and overburden distributed over the ground surface, b) excavations in both open pit or underground mining which disrupt the surface, c) dust and erosion problems which are often associated with tailings, d) possible contamination or depletion of a local aquifer in a water poor area, e) disruption in wildlife habitat by using tailings areas, mine areas, and associated mining activity. Although in situ methods will not face the tailings problems, disadvantages are also present: a) thermal pollution involved with large amounts of heat put into the ground, b) possible contamination of aquifers, c) surface spills due to machinery failures, d) or possible surface subsidence with accompanying land disturbance; e) noise could be a problem depending on the equipment being used.

Processing - A well designed pre-refining system of processing tar sands should meet current Federal air standards. The sulfur and nitrogen removed from the bitumen could become a source of air pollution with faulty plant design. Metals removed from the bitumen and associated with the carbon residue unless adequately disposed of, could be a local pollutant. Noise, lighting, and activity associated with a plant could have a detrimental affect on wildlife and aesthetics. Development of the area to house workers and family will cause associated drains on local water supplies and destroy the natural appearance of the area.

Transporting Syncrude - In this final stage, all the impacts of the other stages will have their cumulative effect. Should any petroleum transporting pipelines be ruptured in the dry remote areas as those particularly associated with tar sand resources, considerable time would be necessary to restore the environment. Road transportation by trucks could cause oil spills and dust problems. Rail or pipeline transportation of the syncrude would also be subject to spills through ruptures, caused by natural catastrophies or human error.

Summary - Most tar sands of commercial interest in the United States are located in Utah. Although considerable production from large Canadian deposits can be expected before 1985, Utah deposits have a number of obstacles blocking their development. These deposits are located on lands that have considerable recreational appeal and proposals have been made to make the land into wilderness areas, national parks, or other recreational areas. A second problem of favorable legislation in leasing "Asphalt Minerals" exists. High capital cost, and lack of a good local water supply also hinder development, although the syncrude produced compares favorably with natural crude.

Environmental problems appear in the exploration, mining, processing, and transportation of syncrude. The extent of local disturbance is partially determined by whether mining-extraction or in situ techniques are used. Wildlife and aesthetics would not escape a detrimental effect.

3. Hydrogen

a) Description of the Alternative

The basic technology of using hydrogen as an alternative to fossil fuels exists and although energy intensive, it leaves the greatest obstacles to this relatively pollution free source of energy a matter of economics and timing. By passing a strong electric current through water in a process called electrolysis, water can be separated into its main gaseous components oxygen and hydrogen. The hydrogen can be piped as a gas or subsequently liquified and shipped to be used as a fuel.

Prior to 1958, liquid hydrogen was produced only in small quantities and was primarily a laboratory curiosity. The 1972 hydrogen production was more than 12 billion pounds in the U.S. alone, and is used primarily in making refined petroleum products and chemical synthesis. Only a small fraction of this total production comes from the electrolysis of water, the great preponderance being produced by much cheaper methods of breaking down natural gas, oil and to a lesser extent coal through various catalytic streams and partial combustion processes.

Future speculations for massive hydrogen producing facilities include great floating platforms some miles offshore in the oceans. These platforms would house a series of big nuclear power plants which would generate power for spot decomposition of sea water by electrolysis. The hydrogen produced could be piped ashore. The potential advantages

of such a system are numerous. Hydrogen gas could be piped to its point of use at about one-eighth the cost of sending an equivalent amount of electricity through high-voltage overhead cables. Underground pipe transmission of gaseous hydrogen would eliminate unsightly overhead wires. Unlike electrical capacity which is difficult or inefficient to store, hydrogen could be stored as gas in underground cavities or as a compressed liquid in large insulated tanks to meet fluctuating power demands. Already under development are fuel cells which convert hydrogen and oxygen directly into electricity. Advanced electrolytic cells have also begun development which work by feeding in current to catalytically separate oxygen and hydrogen at a $1/4$ - $1/3$ reduction in power required.

The major advances made in hydrogen technology in the last decade are largely a spin-off of rocket and space programs. Liquid hydrogen engines have powered nine astronaut crews safely to the moon and back. In the future these engines are scheduled to play an even larger role in the space shuttle.

The economics and timing of hydrogen's first use as a fuel are complex matters. Presently liquid hydrogen is only about 50% more expensive than gasoline on a btu per unit weight basis since liquid hydrogen is so much higher in energy content. Actual cost projections for the electrolytic production of hydrogen range from a low of \$0.04 per pound using electrical energy from a larger breeder type reactor to

about \$0.12 per pound for other energy sources. Presently gasoline costs of production are about \$0.02 per pound. Hydrogen gas is so light it cannot match natural gas in heat value or a volumetric unit basis. The first hydrogen gas should enter the economy in hybrid gas mixtures that stretch natural gas supplies or may be mixed with synthetic gas products from coal perhaps before 1980. It is possible to convert present gas lines to handle hydrogen though at considerable changeover costs. Transmitting costs of the lighter gas would double or triple, as well as the need for tighter more carefully maintained piping systems, even though the lighter gas could move more rapidly.

With some mechanical modifications all types of internal combustion engines can burn hydrogen cleanly. In the summer of 1972, at the Urban Vehicle Design Competition of 63 experimental cars, the two least polluting were cars converted to run on hydrogen, one of which was the only car to exceed the 1975-76 Federal emission standards. Buses, trucks, ships, locomotives can all run on hydrogen with their present engines although somewhat less efficiently. It can also be burned in the home for heating or cooling. In any combustion of hydrogen as a fuel the only major waste product is water. Additional uses, as the direct reduction of iron ore, dispense with coal and coke use as is already being done at several steam power plants.

With all the exciting possibility, conversion costs remain extremely high, particularly to the consumer. Enormous investments of capital

will be necessary as well as demonstration projects to work out technical problems. It is possible that the use of hydrogen as a fuel could be substantial by the mid-1980's. Large amounts of energy needed for electrolysis could presently be provided only by fossil fuel which would not relieve energy supply or environmental problems.

Projections of this alternative remain highly speculative due to its largely experimental nature and its early stage of development.

4. Biological Energy

Biological energy has attractive prospects in two major areas. One is the production of alcohol from crops, particularly unused crop surpluses, and the other involves the conversion of organic wastes into usable oil.

The efficiency of U.S. agriculture has advanced so fast that for several decades crop production has exceeded demand except in times of international conflicts and in early 1973 when heavy international buying coupled with unusually bad weather drained surplus stores. Average farm production has increased about 80% in the last three decades, largely owing to better yielding seeds and greatly improved "know-how". Thus, to meet our crops needs, we plant fewer acres and require fewer farmers. 1/

Agriculture provides the major current source of renewable energy. Forests, cultivated crops and pasture land may be used repeatedly under proper management. Agriculture production is, however, subject to weather, diseases, wind, and other natural conditions which cannot yet be completely controlled. Nevertheless average production in excess of priority requirements for domestic food, feed and fibers is believed by 1985, and beyond, barring natural disasters or national emergencies. The production of cereal grains and their conversion

1/ New Energy Forms Task Group, 1971-1985, Other Energy Resource Subcommittee of National Petroleum Council Committee on U.S. Energy Outlook, 1972.

through fermentation to usable ethyl alcohol fuel; the collection and use of such residues as straws, corn cobs, hulls and shells for fuels; the growing of crops for fuel energy; and the conversion of animal by-products into fuels are all possibilities.

Agricultural fuels would normally be more expensive than such traditional fuels as coal, gas, oil and waterpower. Increasing U.S. needs for energy, requirements for pollution abatement and many other economic factors could, however, materially change the future role of agriculture as a source of industrial energy.

Of the approximately 2,260 million acres of U.S. land available, about 25% is classified as forest and woodland and about the same proportion is land suitable for cultivation. Most of our woodland will probably be required to meet the predicted demands for lumber, pulp and paper industries, and thus will offer only minor possibilities for contributing to additional U.S. industrial energy supplies. On an average, however, only about 60% of the potentially available cultivated land is now farmed for crops. Yields of cereal grains on these lands have, on an average, increased about 3% annually for the past decade. This increase has exceeded the U.S. production growth, even though the amount of cultivated land has decreased. Thus, unused acres constitute a potential source of energy for the foreseeable future.

A logical sequence of energy conversions is to use this land to produce cereal grains, which are largely carbohydrate, and then to convert these

grains by fermentation into ethyl alcohol, which is a convenient combustible fuel readily usable in motors. If we assume that the 100 million acres, or about one-half of the acres not now required, are used to produce the grain for alcohol at a yield of 70 bushels per acre, this would be equivalent to about 18 billion gallons of motor fuel consumed in the U.S. in 1970. Since ethyl alcohol contains only 65% of the energy content of gasoline, on a gallon basis, the actual energy replacement would be only 14%.

The cost of this ethyl alcohol from fermentation would be many times higher than the cost of present motor fuel. Even so, this tremendous energy potential must be considered in any assessment of future energy sources.

The quantity of organic waste generated in the United States annually is enormous and will continue to increase. Below are summarized various amounts of wastes produced and amounts available as well as potential for conversion into oil and gas. 1/

According to the study below, 1971 collectable agricultural residues in the U.S. amounted to over 130 million tons annually which an oil potential of 170 million barrels, roughly equivalent to 47 million tons of low sulfur coal. To produce the oil from waste, the organic material is treated with carbon and water at 250°-400°C. and 2000-

1/ Data from Bureau of Mines.

5000 psi pressure. This oil product has a heating value of 15,000 btu per pound and the total energy potential would be on the order of 2000 trillion btu. High collection and processing costs, incomplete technology, along with high capital requirements, prevent this energy source from being economically competitive. Presently only one continuous unit with a capacity of 20 pounds per hour is being operated on a test basis. Although the total potential energy from organic waste is enormous and growing, economic considerations will likely prevent this source from having a significant effect on the U.S. energy picture by 1985.

Estimates of Organic Wastes Generated, 1971 and 1980	1971 Organic Solids Available for Conversion		
	1971	1980	
Source:			
Manure mil. tons/year . . .	200	266	26.0
Urban refuse do	129	222	71.0
Logging and wood manuf. residues . . do . . .	55	59	5.0
Agriculture crops and food wastes ^{1/} . . do . .	390	390	22.6
Industrial wastes do	44	50	5.2
Municipal sewage solids do	12	14	1.5
Miscellaneous organic wastes . . do	<u>50</u>	<u>60</u>	<u>5.0</u>
Total do	880	1,061	136.3
New oil potential . . million barrels	1,098	1,330	170
Net gas for fuel potential . . tril. cu. ft..	8.8	10.6	1.36

Environmental Considerations - To use crops to create alcohol is not likely to raise any more pollution, in fact, proper farming techniques would probably reduce soil erosion and increase productivity of the land.

^{1/} Assuming 10% dry organic solids in major agricultural crop waste solids.

To use animals waste for conversion to fuel would have the obvious advantages of disposing of a pollutant itself and recycling it into a useful product. Areas of high population density, produce greater wastes and would have a locally available source of fuel in proportion to their population. Water quality problems associated with organic wastes could be alleviated. The residue would be sterile although large amounts of bulk material would still have to be placed somewhere, perhaps as land fill.

The oil produced has properties varying with the type of material composing the waste. Shown below are the sulfur contents of oils produced from various sludges. 1/ All of them meet the Federal fuel standards of 0.7% sulfur. A distinct advantage in waste conversion would be to reduce demand on natural resources commensurate with the amount of oil and gas made from these wastes.

	<u>Percent Sulfur</u>
Pineneedles and twigs.	0.10
Sewage sludge.64
Municipal refuse13
Cow manure37
Cellulose.003-.2

1/ Bureau of Mines data, 1971.

5. Solar Energy

Solar energy is a source of both heat and electromagnetic radiation and possibilities exist for both direct and indirect use of this energy. Fossils fuels are representative of solar energy stored from earlier periods in the earth's history, which, when ignited, release the energy plants and animals accumulated eons ago. An indirect way of using solar energy in more recent history would be burning fuel, wood or plants directly, while direct use would be a solid state solar cell.

Four characteristics of solar energy deserve particular notation.

- (a) it is a diffuse, low intensity source of energy;
- (b) the energy is spread over various frequencies (i.e., distributed over the various wave lengths of light);
- (c) its intensity is continuously variable during the daylight hours, is zero at night, and is subject to weather and seasonal variations; and
- (d) its availability differs widely between geographic areas.

A consequence of the diffuse nature of solar energy is that it does not naturally produce the high temperature characteristic of combustion processes. This is a definite disadvantage since high temperatures make possible greater thermodynamic efficiency in energy conversion.

The U.S. land area intercepts each year about 600 times its total 1976 energy requirements at an intensity of radiation of 1 KW M^2 or less. 1/ At a 10% efficiency each square meter of active surface will produce not more than 100 watts of peak power.

Such heat can be used for electricity generation, space heating, cooling, and processing of industrial materials. The Solar Energy Laboratory of the University of Florida at Gainesville conducts extensive research in solar energy utilization. Among the applications under development are solar water heating, swimming pool heating, home heating, solar baking, solar distillation, solar power plants, solar cooking, solar furnaces, solar pumps and turbines, and solar sewage treatment. The following tables show the state of development and technical problems of solar energy applications.

1/ IT&T Consultative Committee, 1970 Primary Sources of Energy.

Present Status of Solar Utilization Techniques

Application	Status					
	Research	Development	Systems test	Pilot plant demonstration	Prototype plant	Commercial readiness
Thermal energy for buildings						
Water heating	X	X	X	X	X	X
Building heating	X	X	X			
Building cooling	X	X				
Combined system	X	X				
Renewable clean fuel sources						
Combustion of organic matter	X	X	X	X		
Bioconversion of organic materials to methane	X	X	X	X		
Pyrolysis of organic materials to gas, liquid, and solid fuels	X	X	X	X	X	
Chemical reduction of organic materials to oil	X	X	X			
Electric power generation						
Thermal conversion	X					
Photovoltaic						
Residential/commercial	X					
Ground central station	X					
Space central station	X					
Wind energy conversion	X	X	X			
Ocean thermal difference	X	X	X			

X indicates effort is underway but not necessarily complete.

1

Source:

Solar Energy as a National Energy Resource, NSF/NASA
Solar Energy Panel, Dec. 1972, p. 8.

Summary of Major Technical Problems

Application	Major technical problems to be solved
Thermal energy for buildings	Development of solar air-conditioning and integration of heating and cooling.
Renewable clean fuel sources	
Combustion of organic materials	Development of efficient growth, harvesting, chipping, drying and transportation systems.
Bioconversion of organic materials to methane	Development of efficient conversion processes and economical sources of organic materials.
Pyrolysis of organic materials to gas, liquid and solid fuels	Optimization of fuel production for different feed materials.
Chemical reduction of organic materials to oil	Optimization of organic feed system and oil separation process.
Electric power generation	
Thermal conversion	Development of collector, heat transfer and storage subsystems.
Photovoltaic	Development of low-cost long-life solar arrays.
Systems on buildings	High temperature operation and energy storage.
Ground station	Energy storage.
Space station	Development of light-weight, long-life, low-cost solar array; transportation, construction, operation and maintenance; development and deployment of extremely large and light-weight structures.
Wind energy conversion	Integration of large wind conversion system with suitable energy storage and delivery systems.
Ocean thermal difference	Large low pressure turbines, large heat exchangers, and long, deep-water intake pipe.

Source:

Solar Energy As A National Energy Resource, NSF/NASA
Solar Energy Panel, Dec., 1972, p. 9.

Properties of solar radiation are responsible for photosynthetic conversion which also converts and stores energy.

About half the energy in the solar spectrum lies in wavelengths usable in photosynthesis. The efficiency of this half can be in the neighborhood of 50 percent, giving an overall possible photosynthetic conversion of 25 percent. In experiments, efficiencies in the usable spectrum ranged from chlorella (a green algae) at 20 percent conversion efficiency to about 2 percent for sugar cane. Experiments in Japan to use chlorella have always fallen short of economical use as food. Consequently using it for fuel with a lower unit value than food would also be uneconomical. Since chlorella rates high in efficient conversion of solar energy, other plants don't appear to hold good prospects for useful conversion of solar energy.

Non-biological solar processes are based on either of two fundamental concepts: flat-plate collectors or focusing collectors. Flat-plate collectors consist of flat, blackened surfaces to absorb solar radiation. On the plate, solar radiation is converted to another form of energy usually heat, which is removed from the plate usually in the form of heated water or air. Flat-plate collectors generally operate in a fixed position.

The focusing collector consists of an optical device (a parabolic collector) to focus the beam component of solar radiation on a receiver

smaller than the reflector. The focusing collector allows energy collection at higher temperatures than the flat-plate collector. The intensity of radiation on the receiver may range from 2 to 3 times to 10,000 to 20,000 times that of the incident beam of solar energy on the optical system. At all but the lowest ratios, some degree of "sun tracking" is needed as the direction of the incoming beam radiation changes.

With very few exceptions, all practical solar energy systems now in use are flat-plate collector systems. Materials, costs, and operational difficulties have prevented widespread application of focusing collector systems.

The silicon cell, developed about 15 years ago, has proved to be a reliable means for this direct conversion of solar radiation to electricity for applications in outer space. The generation of significant amounts of power, however, requires the connection of extremely large numbers of cells. The capital cost of silicon cell arrays results in power costs on the order of \$2.00 to \$5.00 per KWH. Thus, the cost is about 1,000 times that of conventional power sources.

Another potential application of solar energy is use of thermal gradients to extract the solar energy stored in the surface layers of the ocean. The summer sun melts down the polar ice, which slides

to the depths of the ocean and moves toward the equator. Above the cold deep water, the surface layers in the tropics remain at a temperature above 80 F. This difference in temperature can be used to generate electricity.

Several proposals have been made to apply this concept to the warm waters of the Gulf stream, which approaches close to the southeastern coast of Florida. The temperature difference between surface and deep water ranges from 27° F to 39° F. The theoretical efficiency of conversion of heat into useful work of about 5 percent is possible at the surface temperature of 72° F.

One scheme to exploit thermal gradients envisages a submerged floating platform. The surface water is used to boil propane at high pressure. The propane gas then powers a turbine to generate electricity. The propane is cooled by the deep ocean water and returned to the boiler. Floating power plants could be located either well out in the moving eater of the Gulf stream or near shore in nearly stagnant water. Preliminary estimates of the capital cost of such plants is from \$200 to \$400 per KW of capacity. These plants could also be used to produce fresh water, and through electrolysis, hydrogen and oxygen. Another possibility is cultivation of shell-fish in the nutrient rich cold water brought up from the deep ocean. Multiple uses of thermal gradient plants would make the economics more favorable.

At the University of Massachusetts, Amherst, William Heronemus and his colleagues are preparing preliminary designs for a submerged power plant in the Gulf Stream. One proposed site is the western edge of the Gulf Stream about sixteen miles from Miami. The concept being considered now is a modular design with six turbines in each of two hulls, hooked together. Towers to the surface would provide ventilation and access to the plant. The station would generate about 400 MW of electricity.

Ocean thermal gradient systems appear to offer the possibility of becoming cost competitive with other sources. Much work remains to be done on design of the plants, environmental effects, transmission of electricity to shore, and selection of the working fluid (the fluid which is vaporized by the hot water and then expands through the turbines and is condensed for reuse).

Among the potential applications of solar energy, residential heating and cooling has the highest chance of success. Solar water heating has long been used in southern Florida, although less extensively than in the past because of the availability and low cost of natural gas. The main elements in solar water heating are a flat-plate collector and an insulated storage tank. Water circulates through the collector, is heated, and is held in the tank for use when needed. Solar water heaters are commercially manufactured in Australia, Israel, Japan, the U.S.S.R., and, on a small scale in the U.S.

The technology of solar water heating is well developed. Product engineering and large scale manufacturing may reduce costs and increase use.

Solar space heating is not yet as advanced as solar water heating. In the past decade, about 25 houses have been built in the U.S. with heating systems powered largely by solar energy. The University of Delaware has completed an experimental house, called Solar One, that will use solar heating and cooling and will convert sunlight into electricity to run home appliances.

Extensive application for solar power exists in home heating using relatively inexpensive collectors costing \$2.00 - \$4.00 per square foot and using auxillary heating when necessary. A 1967 study of this example is used below. 1/

Table VIII-3
SOLAR HEATING COST COMPARISON

		<u>Cost of heat (\$/10⁶Btu)</u>		
<u>Climate classification</u>		<u>Electricity</u>	<u>Gas-Oil (average)</u>	<u>Fuel cost only 75% combustion efficiencies</u>
Santa Maria: Mediterranean or dry summer, sub-tropical	1.10-1.59	4.36	1.52	
Albuquerque: Tropical and sub-tropical steppe	1.60-2.32	4.62	1.48	
Phoenix: Tropical and sub-tropical desert	2.05-3.09	4.25	1.20	
Omaha: Humid continental warm summer	2.45-2.98	3.24	1.18	
Boston: Humid continental, cool summer	2.50-3.02	5.25	1.75	

1/ The International Telephone and Telegraph Consultative Committee, 1970 Primary Sources of Energy.

<u>Climate Classification</u>	<u>Solar Heat</u>	<u>Electricity</u>	<u>Gas-Oil (average)</u>	<u>Fuel cost only 75% comb. efficiencies</u>
Charleston: Humid sub-tropical	2.55-3.56	4.22	1.26	
Seattle/Tacoma: Marine West Coast	2.60-3.32	2.1	1.92	
Miami: Tropical savannah	4.05-4.64	4.90	2.27	

A long-range objective is large-scale production of electricity using either arrays of large collectors or even satellites equipped with solar cells that would surmount the problem of cloudy days. These schemes are not likely to be practical for one or two decades.

The sun provides a pollution-free, non-depleting source of energy. Few applications of solar energy are cost-competitive with other energy sources at the present time. However, solar energy will become more attractive as technology advances and the costs, environmental and otherwise, of the other energy sources rise. Residential heating and cooling has the highest potential for short-term application.

The following table compares estimated costs of electricity generated by fossil fuels and solar power. The data illustrate the high capital costs of solar power.

Electrical generation costs comparisons (estimated)

	Type of Powerplant				Satellite solar powerstation			Terrestrial solar powerstation
	Coal-fired	Oil-fired	Gas-fired	Nuclear	Low	Med.	High	
Unit investment cost of plant, \$/kw	200	140	130	300	1,400	2,100	2,600	1,100
Annual fixed charges, percent of investment	17	17	17	17	17	17		17
Kilowatt-hours generated per year per kilowatt capacity	7,000	7,000	7,000	7,000	8,760			4,000*
Efficiency, percent	34	34	34	33	11			30
Cost of fuel, ¢/10 ⁶ Btu	36.2	55.2	29.4	17.5	0			0
Cost of electricity, mills/kwh:								
Plant investment	4.8	3.4	3.2	7.3	27.2	40.7	50.5	46.7**
Operation & maintenance	1.0	0.6	0.5	0.4	Undetermined			Undetermined
Fuel	3.6	5.5	3.0	1.7	0			0
Total	9.4	9.5	6.7	9.4	---	---	---	---

*Maximum; assumes no facilities for storing electricity for use at night or on cloudy days.
 **Less if facilities for storing electricity are available.

Source: Compiled by Division of Fossil Fuels, U.S. Bureau of Mines.

The Department of the Interior, Bureau of Land Management, is using solar power in mountain top radio communications sites. The first units were installed about ten years ago. Today, there are about fifteen units in Alaska and about forty in remote areas of other states. The Bureau plans to install or convert many more such units in the next few years. The silicon solar panels cost \$100 per watt a few years ago and now cost \$50 per watt. Panels with a large variety of wattages are available. Developing technology and increasing competition among producers may lower costs to about \$10 per watt in the next five years. Installations of this type can be made with minimal environmental impact since access roads are not required and inspection and maintenance are infrequent. The units are being used instead of propane powered thermo-electric generators since propane is in short supply and must often be flown in to the sites by helicopter. Propane delivery to some sites requires a four hour trip at a cost of about \$500 an hour for the helicopter. The solar panels are used to charge batteries that supply power to radios. The units can be preassembled, flown in by helicopter, and installed in a few hours.

The Federal Government has set aside funds for solar energy research within the RANN program (Research Applied to National Needs Program). The purpose of this program is to focus scientific research on problems of national importance, and contribute to their practical solution. The program is implemented primarily through universities.

Fiscal year 1972 funding for solar energy was \$1.7 million, FY73 funding was \$4.2 million, and FY74 funding was \$12.2 million. The objectives of the solar energy activity are to emphasize research in the following three areas of solar applications:

Economical systems for heating and cooling of buildings;

Economical systems for producing and converting organic materials to liquid, solid, and gaseous fuels; and

Economical systems for generating electricity.

Expected accomplishments stemming from this research include an evaluation of the technical, economic, environmental, and social factors related to practical solar energy systems in seven areas:

Solar thermal energy for buildings;

Photosynthetic production of organic materials and hydrogen;

Conversion of organic materials to fuels or to energy;

Solar thermal conversion for electric power generation;

Photovoltaic conversion for electric power generation;

Power from atmospheric circulation; and

Power from ocean temperature differences.

6. Tidal Power

Tidal power is a hydroelectric energy source similar to other water power sources except it is derived from the alternate filling and emptying of a bay or estuary that can be enclosed by a dam. The total tidal power dissipated by the earth is enormous, largely accounted for by oceanic tidal friction in bays and estuaries around the world, although theoretically, it could be captured and converted to electric power. Despite this total potential, practical considerations have eliminated all geographic areas except where tidal behavior, range, and water displacement are extremely favorable.

Two plants are presently operating, the larger is the Rance Plant on the Rance River estuary Brittany, France which was completed in 1967 at a cost of \$90 million, a capacity of 240 MW, to be increased to 320 MW. The present cost is about \$350/KW. The U.S.S.R. completed its first plant on the White Sea in 1969 which has a 1000 KW capacity. Other proposals include the Bristol Channel, U.K., San Jose Gulf, Argentina, and the western Australian Coast. The Canadian government studies 23 sites on the Bay of Fundy, with its potential included below (New Energy Task Group, 1972):

POTENTIAL TIDAL ENERGY

	<u>Bil. KWH/Yr.</u>
Passamaquoddy Bay, U.S./Canada	1.8
Cook Inlet, U.S.	75
Bay of Fundy, Canada	
3 Sites, single effect	13.4
3 Sites, double effect (incoming, outgoing tides)	16.8
Total Potential, of the entire Bay of Fundy	175

Even with the potential of the Bay of Fundy's 35 foot tides, the project was abandoned in 1969 by the Canadian Government as uneconomical.

The only practical opportunities for economic development in the United States appear to be in the vicinity of Passamaquoddy Bay, Maine and perhaps Turnagain Bay in Cook Inlet, Alaska. The higher potentials for Cook Inlet is negated by economics and distance from the market. Passamaquoddy Bay has a tidal range of 18 feet. Capital costs of as high as \$1 billion for the 1.8 billion KWH/yr. were calculated in a detailed 1964 Senate Subcommittee proposal for development. With enormous increases in demand, the significance of this contribution has lessened and the project has been determined to be uneconomical.

Some possibility exists that with better interest rates and a decline in alternate energy sources the Canadian Government will develop a portion of the Bay of Fundy before 1985. Some of this power could become available to the New England region of the United States.

Assuming a maximum of 10 billion KWH from this source could be available by 1985, this would still be only 2% of the projected electrical energy required by the New England region at that time. The attraction of the renewable nature of tidal energy is a great advantage although the total amount of energy is relatively low.

Environmental problems would be considerable. Although no air pollution would exist, damming with alternate filling and emptying of bay and estuary areas would effect shipping, drainage, sport and commercial fisheries, wildlife, water quality, aesthetics, recreation, accumulation of sands and silts, as well as numerous other uses of present bays and estuaries.

7. Wind Energy

Description of the Alternative

Energy can be obtained from the wind by means of a device which will extract energy from a moving mass of air. A fixed device can capture kinetic energy by rotation about an axis and, coupled to a generator, convert it into electricity. Economical power generation requires an average annual wind velocity of about 30 mph, a nearly constant magnitude, and topography in which boundary - layer effects are minimal.

The advantages in using wind energy are the following: a) the supply is inexhaustible; b) it is available in many parts of the world; c) the energy is free on the site of production. Some of the practical disadvantages are: a) the low energy density of the wind; b) the wind velocity is unpredictable in time and magnitude, c) the low conversion efficiencies of aeromotors; d) the effect of icing conditions and weather on aeromotors, and e) the high cost of money required for the capital investment.

In Denmark between 1940-1945 when fuel oil was in short supply, 88 wind-driven installations generated 18,000 mwh for local needs. Below are listed examples of large wind-driven generator installations.

Table VIII-4
Large wind-driven generator installations 1/

Country	Location	Year	Capacity KW
<hr/>			
U.S.S.R.	Balaclava	1931	100
U.S.A.	Vermont	1941	1250
Denmark	Gedser	1959	200
United Kingdom	Orkney	1952	100
United Kingdom	St. Albans	1954	100

By combining wind-driven generators with diesel standby units continuous, small-scale, dependable power can be locally generated.

This method has supplied lighthouses for over ten years at several locations, but at a capacity of less than 10KW. Presently the only major research project to harness the wind's energy is at the University of Hawaii with a budget of just over \$100,000/yr.

The following table shows the maximum electrical energy production from wind power for different regions of the U.S. as estimated by the NSF/NASA Solar Energy Panel. The panel suggests that assuming intensive research and development effort and successful development of practical, economically competitive systems, this maximum could be achieved by the year 2000 and would provide about 19% of annual electricity production in that year.

At the present ime, wind energy is not cost competitive because of high equipment, energy storage, and back up equipment costs coupled with the intermittent characteristics of the wind. Research and development is needed in fuel cells, and concepts using wind generated electricity to produce hydrogen. Wind-energy does not appear to be an alternative to traditional large-scale energy sources at this time.

Maximum Electrical Energy Production From Wind Power

Site	Annual power production
(1) Offshore, New England	159×10^9 kWh
(2) Offshore, New England	318×10^9 kWh
(3) Offshore, Eastern Seaboard, along the 100 meter contour, Ambrose shipping channel south to Charleston, S.C.	283×10^9 kWh
(4) Along the E-W Axis, Lake Superior (320 m)	35×10^9 kWh
(5) Along the N-S Axis, Lake Michigan (220 m)	29×10^9 kWh
(6) Along the N-S Axis, Lake Huron (160 m)	23×10^9 kWh
(7) Along the W-E Axis, Lake Erie (203 m)	23×10^9 kWh
(8) Along the W-E Axis, Lake Ontario (160 m)	23×10^9 kWh
(9) Through the Great Plains from Dallas, Texas, North in a path 300 miles wide W-E, and 1300 miles long, S to N. Wind Stations to be clustered in groups of 165, at least 60 miles between groups (sparse coverage)	210×10^9 kWh
(10) Offshore the Texas Gulf Coast, along a length of 400 miles from the Mexican border, eastward, along the 100 meter contour	190×10^9 kWh
(11) Along the Algonquin Chain, 1200 miles, on transects each 35 miles long, spaced at 60 mile intervals, between 100 meter contours. Hydrogen is to be liquefied and transported to California by tanker.	402×10^9 kWh

Estimated Total Production Possible: 1.536×10^{12} kWh

Source: Solar Energy As a National Energy Resource. NSF/NASA Solar Energy Panel, Dec. 1972, p. 69.

B. Conversion Techniques

1. Fuel Cells

Fuel cells are electrochemical devices in which the chemical energy of fuel is converted continuously and directly to low-voltage direct current electricity. The basic process is similar to that of a battery except that the fuel cell is an open system requiring a continuous supply of reactants for the production of electricity. Their potential advantages over more conventional energy conversion systems are their quietness, low temperature of operation, minimization of pollution, reliability, and greater efficiencies. Nearly one and one-half times more electrical energy can be obtained from a ton of coal in a fuel cell system than for a comparable amount burned in a modern conventional power system.

By direct conversion of the chemical energy into electrical energy and elimination of the thermal energy to mechanical energy steps in conventional power generation, fuel cells promise greater efficiency on the order of 50-55%. Their theoretical efficiencies are even higher, but the 50-55% compares favorably with 32-40% for steam electric power plants through nuclear, oil, gas, or coal.

The concept is particularly favorable from the pollution aspects as shown below.

Table VIII-5

COMPARATIVE POLLUTION LEVELS ^{1/}
(pounds per 1,000 kwh produced)

	<u>Gas-fired Central Station</u>	<u>Fuel Cells</u> ^{2/}
Sulfur dioxide. . .	0.3	0.0003
Nitrogen oxides . .	4.0	0.24
Hydrocarbons. . . .	2.8	0.23
Particulates. . . .	0.1	0.00003

The chemical output from fuel cells consists primarily of water and carbon dioxide. Due to the relatively high efficiency, thermal pollution is low.

A number of cells are connected on a series-parallel circuit to produce the desired voltage and power output. This is advantageous in that transformers can be eliminated with any desired voltage and power output obtained by building various combinations of basic units.

The disadvantage of the fuel cells is a matter of economics. Present costs are about \$400/kw compared to \$250-350/kw for future central station generation. Two costs not incurred by fuel cells are transmission costs from the central station and reserve capacity costs. Nevertheless, at \$400/kw, a 12.5 kw installation would cost \$5,000

^{1/} Energy Research Needs, Schurr, S. H., Resources for the Future, Inc., October, 1971.

^{2/} Design features based on data from experimental fuel cells.

and a householder would not likely make this investment when almost no investment is required for central station power. Fuel cells produce direct current and must be fed into an inverter to convert it to alternating current used by most appliances. This adds to the cost. Metal catalysts and fuel purification processes are also partially responsible for the high capital cost and high operating costs.

Since the middle 1950's, hundreds of U.S. and foreign companies have conducted research and development on fuel cells. Successful fuel cells for aerospace (Gemini and Apollo) were developed. Commercial applications on vehicular power, central power, and residential gas total energy have been less successful. The two remaining commercial development programs for off the road vehicles and a gas fueled total energy fuel cell package are unlikely to have a significant effect on fuel use by 1985 since they lack both efficiency and investment advantages over prospective magnetohydrodynamic-topped or thermionic-topped fossil-fuel or nuclear generating stations.

Fuel cells do have some potential environmental advantages such as quietness, low operating temperatures, and absence of toxic wastes, and the use of fuel cells in localized substations could reduce the need for central station power and transmission lines.

However, unless major new developments occur in fuel-cell technology (unlikely, considering the vast amount of work completed), fuel cells

will have little impact on fuel utilization by the end of the century. Should reformer types be developed, normal fuel supply economics will determine which fossil fuel is affected. In any case, the gain in fuel efficiency over conventional converters would be small (10-15%). A breakthrough in direct use of hydrocarbons or in producing pure fuels such as methanol or hydrazine at low cost might have larger impact on fuel efficiency, but it is not likely that these developments will materialize in the near future.

2. Magnetohydrodynamics

Magnetohydrodynamics (MHD) power generation is a technique for electrical generation which passes a hot ionized gas, or liquid metal, through a magnetic field. Such a high temperature one-stage conversion device has the potential of high overall efficiencies. Though the concept of MHD generation has been known for over 100 years, it is only during the past decade that significant technological advances have produced systems which offer promise for use in the electric power field. Three basic approaches to MHD generation are being explored--open-cycle, closed and liquid metal systems.

The MHD open-cycle generation, used as a "topping unit" in conjunction with steam-turbine generation, appears to hold the most promise for MHD central-station power generation in the future. Overall system efficiency is expected to increase to a range of 50 to 60 percent, which could provide a fuel saving of 20 to 30 percent over fossil fuel steam-electric plants. General application of coal-fired MHD topping units by the mid 1980's could effectively extend fossil fuel reserves and enhance the potential for use of coal for power generation. Since the MHD generator would require little cooling water, the combined MHD-steam units would require considerably less cooling water per megawatt of capacity than conventional fossil fueled or nuclear steam-electric units.

Before MHD can be utilized for central power station generation, there are many significant technological problems which must be solved. No economically practical system has yet been demonstrated for burning coal or coal-derived fuels. Designs to date have been small scale with short life-times and lower efficiencies than would be required for utility operation. There are problems of developing long-life MHD channels and electrodes, high temperature preheaters, super-conductivity magnets, seed recovery systems, high temperature metal erosion and corrosion, etc. The high temperatures and gas passage time are conducive to fixation of nitrogen so there may be significant NO_x air quality problems.

MHD research presently is being conducted in England, France, Germany, Japan, Poland, the Soviet Union and the United States. The Soviet Union appears to have made a strong commitment to the development of MHD for commercial use. Soviet engineers express confidence that an open-cycle MHD unit of appreciable power output will be operating in the 1970's but there is yet no evidence of proven economic feasibility. A 75 MW combination MHD steam pilot plant (25 MW MHD and 50 MW steam) is being constructed near Moscow. For the present, only a 25 MW portion of the plant currently is planned for completion and operation. Japan also has made great strides in achieving the high field super conductivity magnets necessary for MHD.

Utility companies, manufactures, research institutions, and the U.S. Government have been actively involved in MHD investigations since

the 1950's. A 1969 Office of Science and Technology report identified many problem areas in which research and development are needed before MHD power system work can proceed to a full-scale prototype. This report recommended that the U.S. Government encourage work on solving the difficult problems of coal-burning open-system MHD systems. In January 1973, at least four relatively modest U.S. efforts on magneto-hydrodynamics were continuing although only one related to practical power generation.

While MHD appears to offer considerable future potential for coal-fired power generation, the technologic and economic uncertainties are still so great that it cannot be considered as a viable alternative power source by 1980. Combustion products from fuels such as petroleum distillates and natural gas give low electrical conductivity in MHD ducts. The thermal efficiency of MHD topped plants with petroleum fuels is significantly lower than with coal or coal gas as fuel. Improvements in the combined Brayton-Rankine cycle, which are likely to occur before 1985, offer serious competition for MHD and has dampened the electrical equipment and utility industries interest in MHD conversion for the present.

It appears that the MHD concept can first emerge as a peaking or emergency power plant with distillate or residual fuels. With adequate funding, a large prototype peaking plant might be available by 1978.

For MHD to be applicable to base load plants fired by coal, a long-term and costly program extending beyond 1982 seems likely. Even if sufficient funding occurs, some probability exists that engineering problems will not be solved in a way that will be practically or economically acceptable. While competitive and lower capital costs have been projected for MHD-topped steam plants, reliable economics must await the demonstration of MHD on a large-scale for long duration. Base load MHD-topped plants fired by coal are far from successful development. Since peaking plants have only a small effect on our total energy requirements, no significant effect from MHD seems likely before 1985.

Environmental Considerations

Increased thermal efficiency would reduce the overall amount of fossil fuel requirement per unit of energy produced which would reduce that amount of pollution associated with the fossil fuel production. The reduced water cooling requirement would result in less thermal pollution impacts on water quality. The wide distribution of coal resources and reduced cooling water demand would promote location of generation stations near the coal resource and population centers, thereby reducing long distance electrical energy transmission requirements or coal transportation. Reduced fuel consumption would result in a lower volume of noxious effluents than would be discharged into the atmosphere by a comparable capacity of conventional power plants.

While there still could be air pollution problems similar to those of other coal uses, increased NO_x problems resulting from high temperature operations also might develop. If coal demand should increase it would require a corresponding increase in surface or subsurface coal mining with the inherent environmental impacts of such mining. While generators could be located close to coal deposits, there would be environmental disruptions associated with transportation from mine to generator, additional transmission lines, development and operation of power station sites, and possible noise problems.

3. Thermoelectric

When two dissimilar metals are joined together in the form of a loop and one of the junctions is held at higher temperature, an electric current will flow. With possible efficiencies in generator technology in the order of 30%, it appears that overall efficiencies of thermoelectric systems could not exceed 10 to 15 percent. Short operating life-times, which result from the instability of thermoelectric elements at high temperatures necessary for higher power operations, and undesirable heat transfer from the hot to cold junctions, which result in low efficiencies, are major obstacles to additional progress in development of this electric energy source. Although thermoelectric generation will doubtless receive continued attention for special low power applications, it would seem to hold little potential for central power station plans in the foreseeable future.

4. Thermionic Generation

Thermionic conversion of heat directly to electricity depends upon the emission of electrons from metal surfaces at very high temperatures--typically near $3,000^{\circ}$ F. The electrons are collected on another closely spaced (0.005 in.) metal surface at lower temperature, typically $1,100$ - $1,600^{\circ}$ F. The device is called a diode, from its close analogy to electronic vacuum tubes. Commonly, the emitter and collector are concentric refractory metal tubes several inches long. They may be constructed in electrical series connection to multiply the 0.7 to 1.0 output voltage of single diodes. Heat may be supplied by fossil fuels or by nuclear fuels and may be transmitted to the emitter either directly or indirectly, as by a "heat pipe".

Since thermionic generators are another type of heat engine, their efficiency theoretically is limited to 35-40%, but the best realized efficiencies are below 20%, at operating temperatures near $3,000^{\circ}$ F. Laboratory system efficiencies do not now exceed 10%. Commercial exploitation of the phenomenon awaits solution of difficult materials problems related to operations above $3,000^{\circ}$ F. and in radiation damage to isotopic-fueled devices. The Federal Power Commission 1972 National Power Survey indicates that the consensus is that future efforts in thermionic development during the next decade will be concentrated in space oriented activities. The principal effort will be directed to the development of nuclear-fueled systems to be

used as power sources for interplanetary expeditions. Even assuming materials problems will be conquered, there is little likelihood of thermionics achieving commercial realization for large scale generation by 1985. This is largely due to the high capital costs of the thermionic system for topping a conventional fossil fuel or nuclear generating system. However, increased fuel efficiency could make them economically attractive and a recent estimate suggests that thermionic topping, would about break even with incremental conventional generating capacity in a modern super critical coal fueled station.

In January 1973, there were at least 11 large scale research projects in thermionic generation funded by various private, governmental, or military groups.

Thermionic development is not sufficiently advanced for an evaluation of potential environmental impacts. Since it is a type of heat engine, the associated heat is a potential source of thermal pollution although coupled into a total energy system it could be used to diminish heat pollution. Its primary advantage lies in reducing the necessity of using fossil fuels by increasing their efficiencies.

9. Combination of Alternatives

In the interest of clarity of presentation this analysis has discussed separately each potential alternative form of energy as a possible substitute to the oil and gas anticipated from the proposed sale. It is highly unlikely that there will ever be a single definitive choice to be made between any potential energy form and its alternatives. Each may have a role to play; some may make major contributions to our energy supplies, while others may be subordinated to lesser roles. Some alternatives may be developed rapidly; others may evolve more slowly-perhaps to make a more important contribution at a later date. Forecasting on the basis of present knowledge of the relative roles of these potential alternatives is a highly subjective exercise which must necessarily include a large measure of judgement as to future trends in such variables as the direction and pace of technological development, the identification of usable resources, the rate of national economic growth and changes in our life style.

The table which follows this section summarizes the pertinent data developed in other sections of this statement as to the possible alternatives to provide the energy equivalent to that projected for the proposed sale. Examination of this table will facilitate consideration of possible combinations of alternatives.

It seems most probable that many of the alternatives outlined in the table will be developed to some degree. Understanding of the extent to which they may replace or complement offshore oil and gas requires reference to the characteristics of our total national energy system. Factors most relevant to the issues at hand are outlined below:

1. Historical relationships indicate that energy requirements will grow at approximately the same rate as gross national product.
2. Energy requirements can be constrained to some degree through the price mechanisms in a free market or by more direct constraints. One important type of direct constraint operating to reduce energy requirements is through the substitution of capital investment in lieu of energy; e.g., insulation to save fuel. Other potentials for lower energy use have more far-reaching impacts and may be long range in their implementation--they include rationing, altered transportation modes, and major changes in living conditions and life styles. Even severe constraints on energy use can be expected to only slow, not halt, the growth in energy requirements within the time frame of this statement.

3. Energy sources are not completely interchangeable. Solid fuels cannot be used directly in internal combustion engines for example. Fuel conversion potentials are severely limited in the short term although somewhat greater flexibility exists in the longer run and generally involves choices in energy-consuming capital goods.

The principal competitive interface between fuels is in electric powerplants. Moreover, the full range of flexibility in energy use is limited by environmental considerations.

4. A broad spectrum of research and development is being directed to energy conversion--more efficient nuclear reactors, coal gasification and liquefaction, liquified natural gas (LNG), and shale retorting, among others. Several of these should assume important roles in supplying future energy requirements, though their future competitive relationship is not yet predictable.
5. Major potentials for filling the supply/demand imbalance for domestic resources are:
- More efficient use of energy
 - Environmentally acceptable systems which will permit production and use of larger volumes of domestic coal.

- Accelerated exploration and development of all domestic oil and gas resources.
- Development of the Nation's oil shale resources.

Of the foregoing increased domestic oil and gas production offers considerable possibilities, since indicated and undiscovered domestic resources total 417 billion barrels of oil and 2,100 trillion cu.ft. 1/ of gas which are estimated to be producible under current technology. However, the feasibility of providing adequate incentive and reducing the uncertainties inherent in petroleum exploration is not known.

6. The acceptability of oil and gas imports as an alternative is diminished by:
 - The security risks inherent in placing reliance for essential energy supplies on sources which have demonstrated themselves to be politically unstable and prone to use interruption of petroleum supplies to exert economic and political pressure on their customers.

1/ USDI, United States Energy: A Summary Review, pp. 22 and 27.

- The aggravation of unfavorable international trade and payments balances which would accompany substantial increases in oil and gas imports.
- Apparent high costs of liquefying and transporting natural gas other than overland by pipeline.

Though this section considered the possibility of combinations of alternatives, in view of the foregoing it seems reasonable to postulate that the basic alternative to the production of the oil and gas from the sale would be an equivalent amount of foreign imports, if they are available. This would be true when considering alternatives to either the entire proposed sale or to any number of tracts deleted from the sale. The problems associated with this alternative have been discussed in the text. It is difficult to predict what alternatives, or combinations of alternatives, would be feasible in the more distant future.

Incremental Production Potential of
Proposed Lease Sale and Alternatives

Alternative	<u>Production Potential</u>	
	Physical Units	Btu (billions)
<u>Proposed Texas #3⁴</u> Sale		
Oil	6,000-12,000 b/d	34.8-69.6
Gas	900-1500 million cf/d	928.8-1548
Oil Imports	166,000-279,000 b/d	963.6-1617.6
LNG Imports <u>1/</u>	933.7-1567.4 million cf/d	963.6-1617.6
<u>Onshore Production 2/</u>		
Oil	6,000-12,000 b/d	34.8-69.6
Gas	900-1500 million cf/d	928.8-1548
Deregulation of Wellhead Price of Natural Gas	Uncertain	
Coal as Solid Fuel	14.6-24.6 million tons/yr	963.6-1617.6
Oil Shale <u>3/</u>	150,000 bbl/d in 1980	870
SNG <u>4/</u>	1920 million cf/d in 1980	1980
Hydroelectric	Negligible	
Nuclear	10-17 thou. MW	963.6-1617.6

1/ Assuming development of a LNG industry with construction of terminal and regasification facilities.

2/ Assuming economic incentives.

3/ Total production of oil shale in U.S. under the most optimistic case, as projected by National Petroleum Council.

4/ Total production of SNG in U.S., projected by Department of the Interior, U.S. Energy Through the Year 2000, Dec. 1972, p. 22.

C. Delay Sale

1. Until New Technology is Available to Provide Increased Environmental Protection

The sale could be delayed until new technology is available; however, basically safe technology is available provided its application and use are properly regulated and controlled. As new technology relating to safety and environmental protection is developed, it can be incorporated with existing requirements and applied to all OCS leases so that bringing on additional production now will not generally preclude adaptation of new advances to the prospective leases. "Zero risk" does not exist but is an idea toward which safety systems are directed. In the history of Federal offshore leasing and production over the past 19 years only 11 spills of 1,000 bbl. or more have occurred in more than approximately 1,500 leases, 10,500 drilling holes, and 1,939 producing platforms.

2. Pending Completion of Studies Concerning the Potential Environmental Impacts of Offshore Minerals Development in General and Oil Spills Specifically

The proposed sale could be delayed pending completion of all studies concerning the potential environmental impacts of offshore minerals development in general and oil spills specifically. Many long-term, ongoing studies relating to these issues are being conducted by the scientific community, industry, and government. The Bureau of Land Management is initiating long-term, ongoing studies of its own both on an inhouse and contract basis. See Section I.G. for a description of the Bureau's present study efforts relating to the OCS program.

A central feature of many of these studies is that they are never really completed in the sense that they rarely reach definitive conclusions with wide applicability, but simply advance from one stage to another, from one level of analysis to another, thereby contributing to a growing area of knowledge and body of literature pertaining to the numerous complexities of environmental analysis. To delay the sale on the basis of incompleted studies would require an indefinite delay perhaps of many years duration. As the recent University of Oklahoma study: "Energy Under the Oceans: A Technology Assessment of Outer Continental Shelf Oil and Gas Operations", points out, current and programmed research on OCS environmental data will help improve our knowledge, however, acquiring a total functional understanding of the coastal environmental is an "extremely long-term goal". Undoubtedly, information gaps and uncertainties will always be associated with offshore minerals development and any delays in such development programs must be judged on the basis of whether or not these gaps and uncertainties are so great, compared to what is known, as to warrant postponement. The OCS oil and gas leasing program will help make available increased supplies of energy resources of Federal lands for national energy needs. Final judgment must rest on a determination regarding whether or not a delay in this proposed lease sale would be in the Nation's best interest.

3. Pending Development of Land Use and Growth Plans Onshore

The proposed sale could be delayed pending the development of land use and growth plans onshore. Timetables for onshore development plans differ from state to state in terms of initial development of plans, updating, revisions, and subsequent implementation. Delay of the sale awaiting such plans could cause the development of the offshore mineral resources to occur in a piecemeal, unordered manner. It could result in a greater degree of coordinated planning between states and the Federal Government especially with regard to coastal areas and would result in the avoidance of potential environmental impacts resulting from lack of coordinated efforts. It should be stated, however, that onshore development must take place within the authority of state and local agencies, and coordination with the jurisdictional agencies is sought throughout the entire leasing and development process.

4. Pending Completed Implementation of Recommendations Made in Reports on OCS Operating Orders and Regulations and a Review of Regulations and Amendment as Necessary

A decision could be made to delay this sale until the implementation of those recommendations made in reports concerning strengthening operating procedures discussed in Vol. I, Section I.G.2 had been completed. During the implementation of these recommendations, a review could be completed of all operating and leasing regulations, OCS orders, and statutory provisions to locate sections that needed revision. Any necessary amendments of the regulations and orders

could be made through the appropriate procedures and if sections of the OCS Act were found to need revision, amendments could be suggested to Congress. In considering this alternative, the existing authority of the OCS Act to prescribe and amend regulations at any time when the Secretary determines it to be necessary and proper so as to provide for the prevention of waste and conservation of the natural resources of the Outer Continental Shelf and the protection of correlative rights therein must be kept in mind. 43 U.S.C. § 1334(a)(1). Any revisions of the operating regulations or the OCS orders which relate to the prevention of waste, conservation of natural resources, or protection of correlative rights could be made at any time and apply to all existing leases. It is unlikely, however, that amendments to the OCS Act or regulations dealing with matters other than the above could be applied to leases in existence at the time of the amendment. If such amendments were felt necessary for leases which may be executed if the proposed sale takes place, they would have to be done before the leases were signed by the parties.

Environmental Impact of a Decision to Delay the Sale

A decision to delay the sale based upon any combination of the four reasons given above would eliminate any environmental impact to the offshore or onshore area of the sale during the period of the delay. The environment of the area would exist during the delay essentially as it does today. Assuming a decision was made to hold the sale at a future date after all the reasons for delay had been

satisfied, the environmental impact would reflect the degree of success achieved in attaining more fail-safe technology, baseline biological data against which the potential impacts could be assessed, land use development plans with which operations could be coordinated, and revised leasing and operating regulations and orders to strengthen the management of OCS operations and minimize the impact of such operations.

It is conceivable that the potential environmental impact of operations resulting from a sale held after such a delay would be of much the same character as those potential impacts discussed in this statement, but that the potential for such impacts occurring would be minimized. Some impacts might be reduced entirely if changes in operating techniques were the result of the review conducted during the delay period. For instance, biological baseline data and other research might suggest that drilling muds are harmful when released into the marine environment. If such findings were made, different operating procedures would no doubt result to eliminate or reduce this impact. Such different operating procedures would have their own environmental impact which would have to be considered.

If this sale were delayed for the reasons given, it is evident that the delay would be for more than just a few months. A delay of at least two years could reasonably be expected to complete baseline studies, develop improved technology, implement land use programs - particularly under the Coastal Zone Management Act, and implement

the recommendations and regulatory changes discussed above. In the event of a delay of that duration, alternative energy sources would be expected to fill the gap left in the needed energy supply during that period. These alternative energy sources have their own environmental impact as discussed earlier in this section of the statement. Depending upon the alternative source or combination of sources drawn upon to meet the demand left unsatisfied by the delay of this sale, the environmental impact to the Nation could be more or less than that anticipated from this sale.

Other than these general statements concerning the environmental impact of delaying this sale, it is difficult to determine the precise impacts should the sale be held at some later date. The changes that might be made in a later sale are speculative at this stage because of uncertainty of the type of baseline data that would have to be gathered, improvements in technology, and revised regulations that could result. It can be said with certainty, however, that prior to deciding to hold a sale at a later date, the environmental impact would be thoroughly assessed.

D. Government Exploratory Drilling Before Leasing

Another alternative to the present leasing system is Government exploratory drilling before holding lease sales. At the present time there is no exploratory drilling on the OCS prior to leasing. The U.S. Geological Survey receives all engineering and geological data from companies who have drilled on leases issued on the OCS. These data and geophysical data purchased on the open market are used by the Geological Survey to develop OCS lease policies and evaluate tracts prior to leasing.

Oil and gas companies spend millions of dollars acquiring geological and geophysical data, and on data processing and interpretations to enable them to compete in lease sales. The value of this information depends upon its exclusive and proprietary nature. Because of the high cost, companies generally combine in "group shoots" and share the expenses of seismic data acquisition or purchase data from geophysical service companies. A very few companies have their own equipment and do their own work under research and development departments. Geophysical service companies acquire data on specific areas on a speculative basis hoping to sell it to several companies. Therefore, although several companies and the Government may have the same data it is proprietary to the purchaser and can not be revealed. Each purchaser believes his competitive edge in its use is his interpretation and application.

Government exploratory drilling would have several advantages. It could establish the existence, possible extent, and quality of oil and gas resources, and signal problems that may occur if development follows. The Government would be in a better position to take the initiative in selecting tracts to be included in a sale, evaluating resource potential, determining pre-sale estimated value, analyzing lease bids, and identifying environmental problems for the protection of sensitive areas through lease stipulations. At the present time, the oil and gas industry sometimes has more seismic data than the Government for some tracts and industry assists Government through the nomination process in the selection of specific tracts in a general area designated for leasing.

The availability of data from Government exploratory drilling would tend to eliminate the need for costly exploratory effort by industry and encourage companies to channel their efforts into the acquisition and development of producible leases. Availability of data from exploratory drilling could encourage smaller companies to participate in leasing by greatly reducing capital outlays required to evaluate tracts and reducing the competitive advantage of a few companies which possess exclusive data. These tendencies would be counteracted to the extent that companies distrusted Government findings and continued to undertake independent exploration and data acquisition.

Also, large companies having the same data and more money could still outbid smaller companies. However, data from exploratory drilling would provide significantly better resource evaluation than any other method.

The cost to the Government of an adequate exploration program would be tremendous, whether the Government contracted out the work or purchased and operated the equipment itself, hired its own personnel, and did all of its own analysis. Each company evaluates in depth only the most promising tracts and those in which it has a particular interest. In contrast, a Government exploration program would require a detailed evaluation including seismic work and coring and exploratory drilling, of extensive OCS areas, not of just a few tracts. Under present practice, the cost of seismic data collection is generally shared by companies in "shooting combines" or the cost is lowered by being "speculative data" for sale to many companies.

A Government exploratory drilling program would result in the Government assuming the risks and costs now borne by companies. Much of the resources devoted to data acquisition and interpretation by private industry would be freed for development and production. Such a Government program would be tantamount to finding the oil for industry and leasing the reservoirs to be developed and produced.

The interpretation of these data to evaluate resource potential involves not only expertise using the latest state of the art but also highly sophisticated equipment. Under the present system, this expertise is found throughout many companies, each of which devotes a great amount of time and money to the development of better interpretative methods. Each company has its own interpretations and special knowledge, resulting in a diversity of approach to data analysis and use. Any company, as well as the Government, can miss the mark in evaluating a particular tract, but each company believes its competitive edge is its superior interpretation and use of data. Under a system where only the Government did exploratory drilling, the discovery rate could decline. Reserves which the Government underevaluated or overlooked might be less likely to be discovered.

The impacts of Government exploration would be essentially the same as industry's explorations. Industry is required to adhere to stringent standards developed by the Government and is inspected by Government employees enforcing those standards. It would be inappropriate to believe the Government would make standards significantly more stringent for its own operations than it has for industry operations.

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-961